An Introduction to Completing a NERC PRC-026 Study for Traditional Generation Applications

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Abstract -- **The NERC PRC-026-1 reliability standard has recently taken effect and may have an increasingly important role in the development of generator protection settings. The intent of PRC-026-1 is "To ensure that load-responsive protective relays are expected to not trip for stable power swings during non-fault conditions". This paper is intended to be an introductory overview for completing a NERC PRC-026 study for a synchronous generator facility from the perspective of a system protection engineer. This paper also provides an overview of power system stability and the response of impedance-based relay elements to system swings. Lastly, this paper includes a comparison of applicable traditional impedance based generator protection methods outlined in IEEE Standard C37.102., with the method used to demonstrate compliance with the PRC-026-1 standard.**

I. Introduction

In response to the 2003 Northeast blackout and subsequent regulation, NERC Protection and Control Standards (PRC) were created. The intent of these standards is to improve the performance and reliability of the North American Bulk Electric Power System (BES). Most PRC standards apply to all protective device elements within the standard's scope without analysis by the planning engineer. PRC-026-1 [1] is unique in that it applies only to those protective elements associated with BES facilities that the system planner has identified as potentially subject to transient instability during network contingency analysis. However, when transient stability study results are unavailable, the standard's guidelines should now be considered industry best-practice when applying load-responsive protective relays in generator protection applications.

This paper intends to provide an overview of how a PRC-026-1 protection analysis is completed for traditional synchronous generator facilities. This paper also provides perspective on how PRC-026-1 criteria and traditional load-responsive generator protective element settings criteria compare, contrast, and lessons that have been learned while completing PRC-026-1 protection analysis.

II. Background for PRC-026-1

After the August 14, 2003 Northeast Blackout, the Federal Energy Regulatory Commission (FERC) raised concerns about the performance of transmission protection systems during stable power swings. These concerns were later included on the official FERC Order No. 733, which directed NERC to develop a Reliability Standard to address protective relays which could potentially trip during stable power swings. FERC cited the U.S.-Canada Power System Outage Task Force reports that identified dynamic power swings and resulting system instability as contributing factors to the 2003 Northeast Blackout's cascading collapse of the system. FERC did acknowledge in this directive that it would not be realistic for NERC to develop a reliability compliance standard that could anticipate every conceivable critical operating condition, conceding that protective relays cannot be set reliably under extreme multi-contingency conditions.

In response to this directive, NERC System Protection and Control Subcommittee (SPCS) developed a detailed report titled, "Protection System Response to Power Swings" [2]. This report undertook a historical event analysis of major North American blackouts from 1965-2013 to determine the role that protective relaying played in operating during stable power swings. The report concluded that protective relay operation during a stable power swing was neither a root causal factor, nor contributory in any of these large-scale outage events. The report did note that during the 2003 Northeast Blackout there were two instances where 345 kV lines tripped in response to a stable power swing during the cascading event. However, SPCS observed that these instances were already well into the cascading blackout event and computer simulations suggest that had these lines not tripped, they would have tripped due to an unstable power swing a few seconds later.

The NERC SPCS report provided several recommendations/observations for the subsequently developed PRC-026-1 reliability standard. These included that out-of-step protection was essential in preventing severe cascading outages by correctly

identifying an unstable power swing and separating portions of the systems—preventing further system collapse. For this reason, out-of-step protection should be biased toward dependability rather than security if both principles cannot be fully satisfied. The report also noted that existing NERC reliability standards, including PRC-019, PRC-023, PRC-024 and PRC-025, have addressed most of the contributing protective relaying factors in the studied historical blackout events. However, the report did recommend that if a reliability standard was developed to address protection system trips during stable power swings—than it should be limited by the following principles.

- Be selectively applied
- Responsibility of its application should be given to those with a system-wide perspective (i.e. system reliability or planning coordinator)
- Applied in instances of known miss-operation of relaying due to a stable power swing

III. NERC PRC-026-1

The goal of PRC-026-1 is to keep available generation and transmission facilities in service during stable power swings to support the BES, reducing the risk of a cascading blackout event due to frequency or voltage instability. This section will provide an overview of PRC-026-1 as it pertains to protective relay analysis. The standard applies to generators, transformers, and transmission line BES facilities.

PRC-026-1 contains four requirements, R1 through R4, the first requirement R1 applies to system planning and the remaining R2 through R4 apply to load responsive relays associated with BES elements identified in R1. The standard also contains two attachments: Attachment A lists the following load responsive protective functions that apply to the standard, and which operate with a delay or 15 cycles or less:

- Phase Distance
- Phase Overcurrent
- Out-of-Step Tripping
- Loss-of-Field

Attachment A also outlines various protective functions which are excluded from the compliance standard, including those that may be load responsive. Attachment B defines the criteria for performing analysis of protective elements covered by the standard. These criteria will be detailed in subsequent sections of this paper.

Requirement R1 states *"Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner or Transmission Owner."*

Requirement R1 includes the following criteria for which the Planning Coordinator shall notify the respective Generator Owner (GO) or Transmission Owner (TO):

1. *"Generator(s) where an angular stability constraint exists that is addressed by a System Operating Limit (SOL) or Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s)."*

2. *"An Element that is monitored as part of an SOL identified by the Planning Coordinator's methodology based on an angular stability constant."*

3. *"An Element that forms the boundary of an island in the most recent underfrequency load shedding (UFLS) design assessment based on the application of the Planning Coordinator's criteria for identifying islands, only if the island is formed by tripping the Element due to angular instability.*

4. *An Element identified in the most recent annual Planning Assessment where relay tripping occurs due to a stable or unstable power swing during a simulated disturbance.*

The standard further clarifies that the Planning Coordinator of a given system area will use methodology already laid out in NERC Reliability Standard FAC-014-2 "Establish and Communicate System Operating Limits". While this paper will primarily focus on the PRC-026-1 compliance requirement related to protection analysis (R2), it's important to recognize that the Planning Coordinator (through notification) triggers the following system protection analysis and requirements. Requirement R2 is also triggered if a protective element has previously tripped due to a stable or unstable power swing.

Requirement R2 states Each Generator Owner and Transmission Owner shall:

3.1 "Within 12 full calendar months of notification of a BES Element pursuant to Requirement R1, determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-1 – Attachment B where an evaluation of that Element's load responsive protective relays(s) based on PRC-026-1—Attachment B criteria has not been performed in the last five calendar years.

3.2 Within 12 full calendar months of becoming aware of a generator, transformer, or transmission line BES Element that tripped in response to a stable or unstable power swing due to the operation of its protective relay(s), determine whether its load-responsive protective relay(s) applied to that BES Element meets the criteria in PRC-026-1—Attachment B.

Requirement R3 relates to the development of a Corrective Action Plan (CAP) for protective elements found that do not meet the criteria outlined in Attachment B of the standard. The CAP is intended to either outline how the GO or TO will adjust the non-compliant protective element(s) to meet requirement R2, or how they will adjust the non-compliant protective elements(s) to meet the exclusion criteria listed in Attachment A. Requirement R3 allows six full calendar months to develop a CAP once a non-compliant protective element is identified under requirement R2.

Requirement R4 covers the implementation of the CAP and accompanying documentation demonstrating completion of the CAP. This requirement also specifies updating the CAP itself and associated documentation if the implementation plan or timetables outlined in the CAP change over the course of the implementation process.

Each PRC-026-1 standard requirement has a specified time period for the GO/TO protective relays to comply, along with required "dated evidence" demonstrating compliance to satisfy the associated measure. The "dated evidence" required by the measures is submitted to the Reliability Coordinator (RC) to use in completing the periodic PRC-026-1 RSAW (Reliability Standard Audit Worksheet) compliance audit.

The PRC-026-1 requirements are phased-in to provide GOs and TOs some flexibility to initially comply with the standard. The first requirement, R1 for system planning, has an effective date of January 1, 2018 and is already being enforced. The remaining requirements applying to system protection and have an effective date of January 1, 2020. Per Requirement R2, GO and TO have 12 full calendar months determine if the identified or notified protective function meets criteria in the standard. Further time is allowed in R3 and R4 to address non-compliance protective functions. Since it is expected that initial planning notifications based on R1 will likely be more numerus, staggered effective dates have been established to help facilitate a smooth transition to comply with the standard.

IV. Power System Swings and Stability

The power system is made up of numerus interconnected transmission lines, generating facilities and load centers. During steady-state conditions there exists a balance between the power generated and power consumed in the system and all parameters describing system operation remain constant for analysis purposes. Each synchronous generator in the system maintains a balance of mechanical input power (from its prime mover) with its electrical power output. In this balanced system state, each synchronous generator maintains its internal voltage and rotor angle at the required relationship with respect other generators to facilitate the required power flows. Under balanced system conditions, generator rotor angle displacement relative to other generators is stable and corresponds to the angular difference between voltages across the transmission system, which dictates power transfer.

Power transfer with respect to the angular displacement of generator rotor angle with other generators in the system can be illustrated with a simple two-source equivalent system. Neglecting resistance, Figure 4.1 illustrates sending and receiving equivalent voltage sources (E_s and E_R) with their respective source impedances (X_S and X_R). The equivalent transmission network X_L represents the system over which the transferred power must travel.

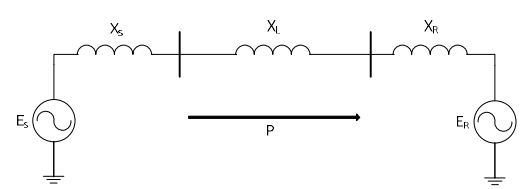

Figure 4.1: Two Source Equivalent System

A simplified expression of the power transfer equation for the two-source system shows the relationship between the generator angular displacement and the power being transferred across the system:

$$P_s = \frac{|E_S||E_R|}{X_T}\sin(\delta)$$

Where P_s = Power sent/transferred
E_s = Equivalent sending end voltage
E_R = Equivalent receiving end voltage
X_T = Total system impedance = $X_s + X_L + X_R$
δ = Angular displacement between E_s and E_R

During steady state conditions the simplified power transfer equation sending and receiving voltage terms can be held at a constant value along with the total system impedance X_T. When plotting the total power transferred as a function of the rotor angular displacement between the sending and receiving-end sources the resulting curve is known as the Power Angle Curve as depicted in Figure 4.2.

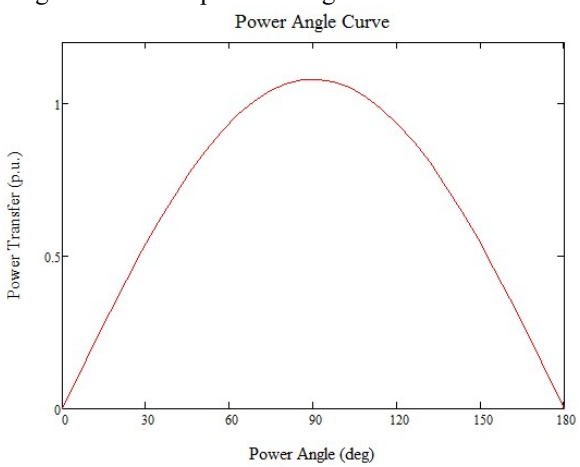

Figure 4.2: Power Angle Curve

The Power Angle Curve illustrates that maximum power transfer occurs when the power angle is at 90 degrees. When the power angle is greater or less than 90 degrees the power transferred is reduced. Typically, systems and transmission lines operate at low angular differences, perhaps 30° or less, with longer lines and weaker systems operating at higher angles [2].

When operating at a steady-state condition, if a sudden change or series of changes occurs to the system parameters this is referred to as a disturbance. Disturbances in the system cause generators to accelerate and deaccelerate in response, with the speed of change controlled by the available mechanical power input and machine inertia. This can be expressed, neglecting rotational and armature loses, in terms of accelerating power P_a, being the difference between mechanical power P_m, and electrical power P_e as shown here:

$$P_a = P_m - P_e$$

When a generator accelerates or decelerates due to a system disturbance it deviates from synchronous speed. Under normal conditions synchronous speed is restored once the mechanical power from the prime mover is adjusted by the generator's governor control to match the required electrical power. During this momentary period of unequal electrical and mechanical power, the machines inertia provides stored potential rotational energy in the form of electric power output when the machine decelerates due to increasing system power demand. Conversely, the machine will accelerate when system power demand drops below the mechanical power input as excess mechanical energy is converted to rotational energy in the generator. This deviation of rotor speed from synchronism can be expressed in terms of rotor angular displacement from synchronism and directly related to accelerating power as shown:

$$P_a = J\omega_m \frac{d^2\,\delta_m}{dt^2}$$

Where $J\omega_m$ is the inertia of the rotor, and this will be constant when the generator is running at a constant speed. δ_m is the angular displacement of the rotor from the synchronously rotating reference axis, in mechanical radians per second. System disturbances cause generator rotor angles to swing or oscillate with respect to one another in search of a new equilibrium operating state. This oscillation of the relative angular displacement of generator rotor angles in response to a system disturbance is referred to as a system power swing.

In terms of system power swings, disturbances usually can be classified into the following:

- Transmission system faults
- Sudden load changes
- Loss of Generating Unit(s)
- Line Switching

A power swing is said to be stable when the angular differences (rotor angular displacement) between all generators decreases after the disturbance and settles into a new equilibrium state. The new system operating point is one where generators maintain synchronism and are operating in their respective mechanically stable operating range, allowing governor controls to match the mechanical power with

the supplied electrical power. The phenomenon of constant ongoing system equilibrium adjustment is found in all large electrical power systems as combined generator power output is matched to changing load demand.

An unstable power swing is one where the rotor angular displacement between the machines in the system continues to increase in response to the disturbance, leading to a loss of synchronism, also called "slipping poles". This may be due to an already high angular displacement across the system due to heavy loading, contingency (such as a line or generating facility being out-of-service) and/or a severe or series of severe system disturbances. When a group of generators (usually in a localized area of the power system) swing together with respect to other generator(s) it is known as a coherent group. The location in a transmission system where a loss of synchronism occurs depends on the systems physical attributes and does not necessarily correspond to boundaries between neighboring utilities. When synchronism is lost within a power system, perhaps between two coherent groups of generators, it is imperative that the system separates into multiple stable islands quickly to avoid collapse of the whole system.

Stability studies are required to evaluate the impact of disturbances on the electromechanical dynamic behavior of the power system. Both steady state and transient stability are evaluated, typically by system planners. Transient stability analysis is typically where power swing performance of a system is evaluated. A system is said to be transiently stable when, after a disturbance, the system returns to a different, possibly significantly different, steady-state operating condition. This is analogous to a stable power swing in a generator. Since generator governor control and the associated mechanical power output provided by the prime mover are relatively slow to change in response to system disturbances, it can be assumed constant to simplify a stability analysis. A system is considered stable when the angular displacement between coherent groups of generators does not exceed stable operating limits during the swing resulting in the coherent groups to lose synchronism.

System stability can be visualized for a two-source, two line equivalent system shown in Figure 4.3, by studying the resultant power angle curves. This sample system neglects resistance, assumes initial steady-state operation prior to the disturbance and allows study of a single generator swing in relation to the equivalent system source. The disturbance first applies a three-phase fault on line #2 in Figure 4.4 and the line #2 breakers then open in response to the line protection clearing the fault, resulting in the final state shown in Figure 4.5.

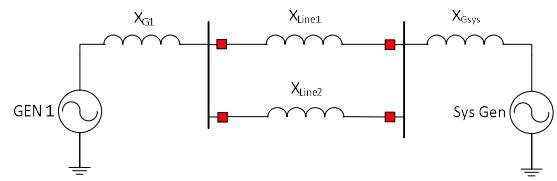

Figure 4.3: Initial 2 Source, 2 Line Equivalent System

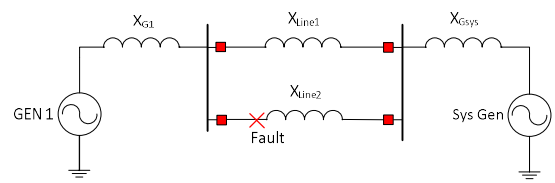

Figure 4.4: Equivalent System with 3-Phase Fault on Line #2

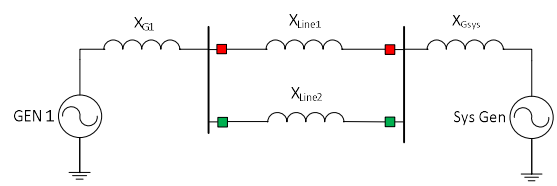

Figure 4.5: Equivalent System with Line #2 Fault Cleared

From the perspective of Generator 1, in Figure 4.3, the power-angle curve initially resembles Figure 4.6 with an initial Gen 1 electrical power transfer P_0 and power angle (with respect the equivalent system source) of δ_0.

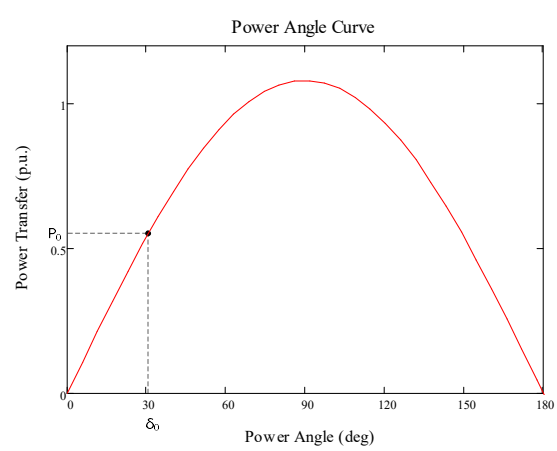

Figure 4.6: Initial Power Angle Curve

At the instant of fault application power transfer capacity across the equivalent system and Gen 1 is reduced. This is reflected in the power angle curve as a reduction in power output and is depicted as the blue

trace in Figure 4.7. As shown in Figure 4.7 the initial system operating power is immediately reduced from P_0 down to the point below on the new faulted power angle curve.

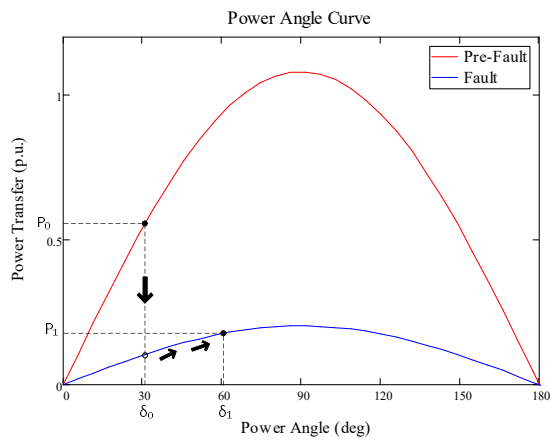

Figure 4.7: Faulted Power Angle Curve

With the immediate drop in electric power output the Gen 1 prime mover mechanical power delivered will cause the machine to accelerate. This acceleration will advance the power-angle along the faulted power angle curve to point δ_1, shown in Figure 4.7. The point δ_1 is determined by the amount of acceleration time allowed before the fault is cleared.

When the faulted line is cleared the power transfer capacity of the system will increase, but at a reduced level compared to the initial system conditions due to the loss of Line 2. This is depicted in Figure 4.8 by the green power curve trace. This immediate increase in electrical power transferred will rise to the level of the post-fault power transfer curve. Recall that the mechanical power delivered by Gen 1 prime mover is assumed constant during power system stability analysis, since governor controls respond slowly to electrical disturbance phenomenon. This means the mechanical power P_m is still equal to the initial electrical power transferred, P_0. Thus $P_m = P_0$ throughout this power swing example. Since P_m is now less than the electrical power being transferred by Gen 1, the machine will decelerate and cause the power angle to advance along the post-fault power-curve plot to the point δ_2. Point δ_2 is dictated by the equal area criterion, where the total machine acceleration time area, A_1, must be equal to the total machine deceleration time, A_2, as shown in Figure 4.8.

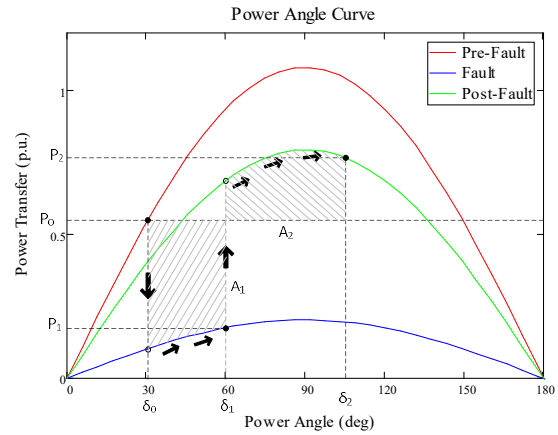

Figure 4.8: Final Power Angle Curve & Equal Area Criterion

In this stability example, as the Gen 1 machine decelerates the power angle increases beyond 90° and power transfer capability will reduce as the power angle increases beyond 90°. Once the machine decelerates at the power angle δ_2 the rotor is restored to synchronous speed with the equivalent system source.

If we assume this is a stable power swing for Gen 1, the input P_m is still less than the P_2 output demanded and this will cause the rotor to continue to decelerate and the power angle to reverse along the post-fault power curve. It is at this point (after the initial swing response) that the governor controls typically have adequate time to respond to the electrical power output demand and increase mechanical power input to match electrical and mechanical power. The degree to which the acceleration/deceleration oscillates along the post-fault or post-disturbance power angle curve corresponds to how well the governor controls are damped. In a stable power swing, the new generator power angle corresponding to the lower power transferred will settle somewhere between 0° and 90°—even if the power angle exceeded 90° during the swing.

If we assume this is an unstable power swing for Gen 1 then the point P_2, along the post-fault power angle curve required to fully decelerate the machine, settles below the prime mover input mechanical power (recall that we are assuming $P_m = P_0$ during the power swing) . If this point is exceeded, equilibrium cannot be restored; the machine will accelerate again and pull out of synchronism. Industry experience has shown that if the power angle advances beyond 120° it is unlikely that the swing will be stable, [2], [4] and [5].

Stability can also be similarly visualized and studied in a system impedance plane or R-X plane. Using the system in Figure 4.3, combine the two lines into a single equivalent line impedance and converting Gen 1 and the equivalent system generation source, Gen Sys, as sending (E_S) and receiving voltage (E_R) sources respectively, then the new system model can be depicted as shown in Figure 4.9. Note that the source impedances of the sending and receiving generator voltage sources are modeled separately and will account for resistances to provide a more realistic equivalent model.

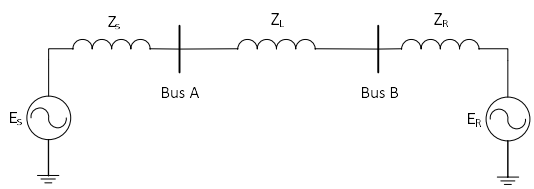

Figure 4.9: Sending and Receiving Source Equivalent Model

The system impedances in Figure 4.9 can be plotted on an R-X plane from the perspective of Bus A. As seen by a line protection relay at Bus A these system impedances appear emanating from the black dot (Bus A line relay) in Figure 6.1. With all the system equivalent impedance Z_S, Z_L and Z_R, plotted on the R-X plane, the Sending and Receiving voltage source points are represented by two terminal points of the system impedances. The total distance between these two system-end voltage source points represents the total equivalent system impedance, end-to-end. This is represented by the dotted line in Figure 4.10. If we draw a circle bounded by the two system end-points, meaning its diameter is the total equivalent system impedance then the center of circle will represent the electrical center of the system.

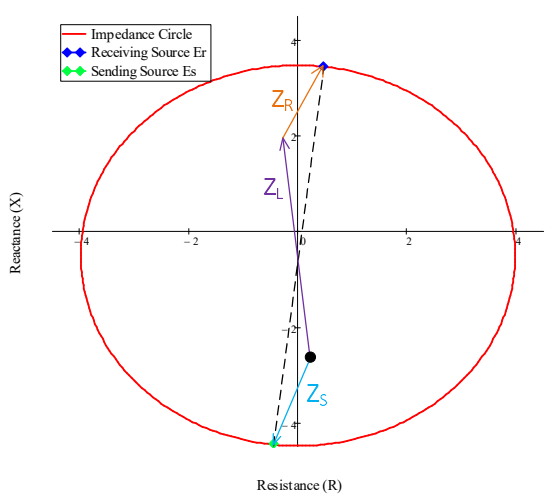

Figure 4.10: R-X Plot of Bus A and System Impedances

If the equivalent system load impedance is plotted in relation to the end-to-end sources and our impedance circle from the perspective of Bus A, it will plot well outside the impedance circle under normal stead-state system conditions. This is shown in Figure 4.11 as the pink X, and is the apparent system load impedance at some operating point under stead-state power transfer level. If we were to draw a line from the system apparent impedance point to each system source voltage point along the circle—then the angle between these two lines is the power angle. Note that in Figure 4.11 the power angle is much smaller than 90 degrees or the maximum transfer power angle.

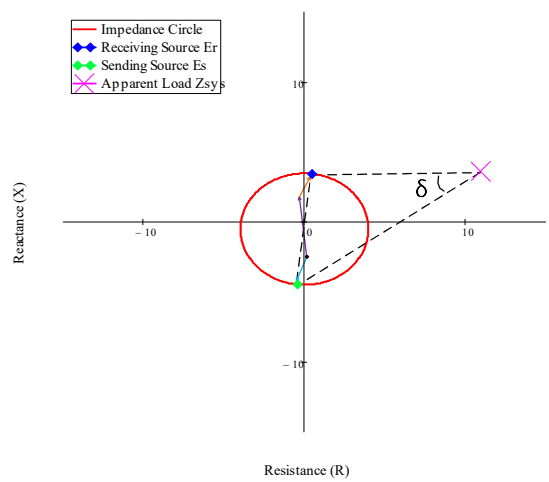

Figure 4.11: R-X Bus A Apparent Sys Load Impedance

When both E_S and E_R sources are of equal magnitude the apparent impedance during a power swing will fall on a straight line perpendicular to the total system impedance along the electrical center of the equivalent system, see Figure 4.12. During a power swing the apparent impedance (as seen from the equivalent system Bus A) is referred to as the swing locus. As the swing locus moves toward the electrical center the power angle δ, will reach 90 degrees when it intersects the impedance circle plotted about the two system sources E_S and E_R, as shown in Figure 4.12. While not all stable power swings will enter the impedance circle, and temporarily exceed a 90° power angle, they will always exit this total system impedance circle and settle at a stable operating point outside the circle. The distance that the swing locus moves inside the impedance circle or the length of time the swing locus stays within the impedance circle depends on the system strength and the relative magnitude of the disturbance that initiated it.

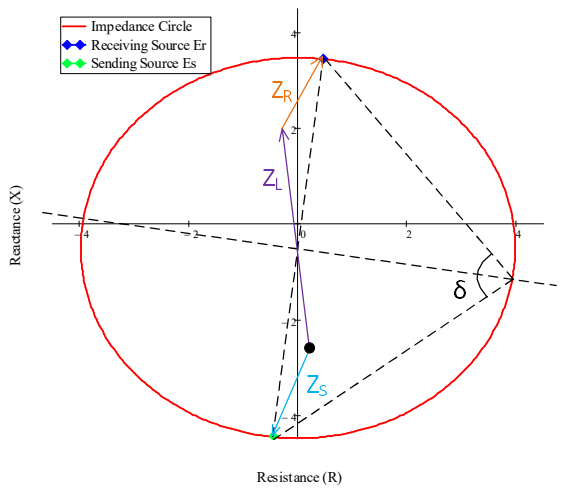

Figure 4.12: R-X Plot Showing Power Angle Between E_S and E_R

If the swing locus reaches 120 degrees and beyond as it moves from right-to-left during a power swing the systems are not likely to recover. The unstable power swing will likely continue moving left on the R-X plane until it reaches the total system impedance at the center of the impedance circle. At this point δ is 180 degrees and the machines are out of phase and have lost synchronism (Out-of-Step) with each other. If the swing locus reaches the electrical center the voltage will be zero at that point, and will be equivalent to applying a three phase zero-voltage fault at the system electrical center. This means both the sending and receiving source will be supplying similar current levels as would be seen during a three-phase fault—putting substantial stress on the system. If the system is not separated at this point, the swing locus will continue to move from right to left eventually reaching the system impedance circle and exiting it where δ is again less than 90 degrees with the sources returning towards synchronism. When the swing locus passes completely through the system impedance circle as described, this is known as "slipping a pole" in a generator. In an unstable swing the sources in our equivalent model will continue to swing against each other and the swing locus will pass back through the impedance circle left to right, slipping another generator pole—each time causing significant stress on the machines in the system.

If the voltage magnitude of the local generator E_S (sending source) and the equivalent system source E_R (receiving sources) are not equal then the swing locus will not pass directly perpendicular to the system total impedance line. Instead, the swing locus will pass through the impedance circle in a circular trajectory either above or below the straight perpendicular line bisecting the electrical center as shown in Figure 4.13.

When the sending source magnitude is higher, relative to the receiving source, the trajectory will pass through above the bisecting perpendicular line. When the receiving source magnitude is higher relative to the sending source the trajectory will pass through below the bisecting perpendicular line. Two examples of these unstable swing trajectories are shown in Figure 4.13 with the black arrows showing the swing locus trajectories through the impedance circle. A similar example of stable swings entering and then exiting the impedance circle is shown with their respective exit trajectories denoted by the blue arrows. The blue final system apparent impedance at the new stable operating point is shown as a blue X.

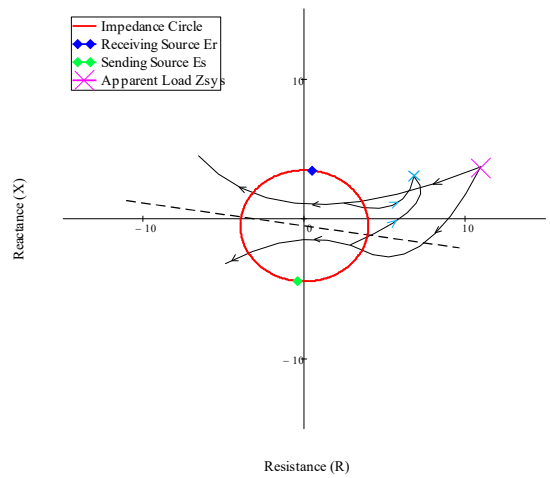

Figure 4.13: R-X Plot Showing Unstable and Stable Swing Loci

In real systems the generator internal voltages are not held constant during a power swing and the excitation systems in each respective generator will behave dynamically based on system demands. This will affect the swing locus trajectory so that it does not follow a perfectly circular path. While the example system we have used to provide a basic overview of system stability is quite simple, accounting for only two generators or a single generator and a system equivalent source — it can, and is often used as the basis for traditional generator Out-of-Step (OOS) protection methods. However, to undertake a system wide stability analysis, perhaps considering contingencies and other system variables, it becomes necessary to use computer analysis employing iterative solutions, often in the time domain.

V. EFFECTS UPON A GENERATOR IN AN UNSTABLE POWER SWING

Let us consider again the simple two-generator system depicted in Figure 4.9 from the perspective of the sending voltage generator, E_S. Now assume a significant system disturbance has resulted in an unstable power swing and the generator pulls out of step/loses synchronism with the equivalent system (receiving voltage source generator). Once synchronism is lost the generator will operate at a slightly different frequency than nominal. This variation in frequency with nominal frequency is known as slip frequency. The effects upon the generator during this condition include the system voltage and generator internal voltage (sending and receiving voltage sources) vectors sweeping past each other at slip frequency. This will produce a pulsating current with peak magnitudes approaching or even exceeding three-phase fault magnitudes as the power angle of the swing locus passes through 180 degrees. If the electrical center is located near or within the generator itself, the pulsating current peak magnitude will be greater than if the electrical center is located further away from the generator on the transmission system. For large generation sources the electrical center typically is near or within the generator step-up transformer (GSU) or the machine itself due to the relatively large impedances of the machine and GSU compared to the system.

The out-of-step condition, while creating high pulsating current levels, does not contain a DC offset. This will somewhat reduce stresses, compared to those encountered during a three-phase fault. However, if the pulsating current levels exceed the sub-transient impedance fault rating of the generator, thermal and mechanical stress can surpass the design limits of the machine. This can be amplified if the generator is not separated from the system since the extreme current peaks will occur every pole-slip cycle. The rotational speed difference between the rotor and the interconnected system will also induce unbalance currents in the rotor, with potentially large negative sequence components. Prolonged exposure to negative sequence currents in machine rotors causes significant and rapid heating leading to thermal damage including distortion of the rotor. Allowing the machine to be exposed to multi pole-slip events may require a complete generator overhaul due to thermal damage of the rotor and stator.

A generator unit experiencing an out-of-step condition is also exposed to severe mechanical torque transients in the prime mover and generator shaft. The generation must be quickly isolated from the system as the fatigue life of the shaft itself can be used up after only a few pole slip events [5]. Prolonged asynchronous operation may also lead to diode failures and insulation stress in a rotary excitation system. The power system adjacent to which the asynchronously operating generator is connected may also experience problems including voltage fluctuations as the generator slips poles. The system as a whole may experience further unstable swings involving more generators and potentially leading to cascading effects including loss of system stability.

VI. PRC-026-1 Study Application

A. Study Outline

The following sections provide an outline of how a PRC-026-1 study is completed for typical synchronous generator facilities. Several traditional generator protection methods, applicable to PRC-026-1, are described, and then compared to what may be required by PRC-026-1 R2 criteria. The flow chart depicted in Figure 6.1 shows the general PRC-026-1 study process once the GO is notified by the system planner that their facility will need to comply with the standard.

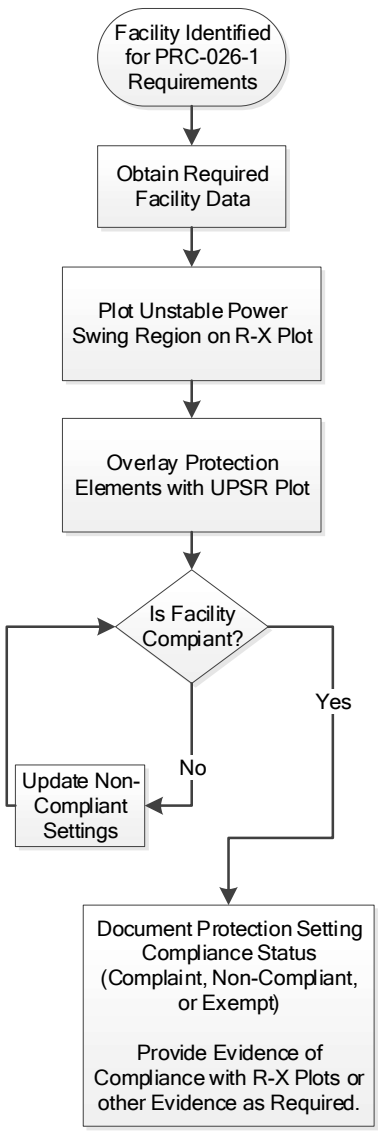

Figure 6.1 – PRC-026-1 Study Process

As shown in Figure 6.1 the study begins with acquiring information about the generator, GSU, and point of interconnect (POI) to the BES. Data required to complete the analysis is not typically used in day-to-day facility operation and will likely require working closely with plant staff to locate OEM performance documentation and factory test reports. A complete data set would include the following:

- Generator MVA, Voltage, & Power Factor Nameplate Information
- GSU MVA, Voltage, Nameplate Information and NLTC position
- Generator Saturated Transient Reactance from the Factory Test Report or O&M Manual
- GSU Positive-Sequence Reactance from the Factory Test Report
- BES Positive Sequence Source Impedance at the POI
- In-service Protective Device Setting(s) and Model Information
- In-service Tap Ratios for Instrument Transformers
- Plant One-line and Three-line diagrams and Protective Relay Schematics

The most common facility information such as generator and GSU ratings can be found on equipment nameplates, while specific generator characteristics like saturated reactance are found on generator electrical data sheets on the O&M manual or factory test reports. One of the least common pieces of information for a facility to have readily available is the system positive sequence source impedance. One method of determining the source impedance is obtaining the three-phase fault magnitude at the POI in either a short circuit or system planning software model. The fault value is then referred to the GSU transformer low voltage windings in ohms primary as shown in the following calculation.

$$Z_{1RC} = \frac{V_{SYS}}{\sqrt{3} * I_{F\_SYS\_3PH}} * \left[\frac{V_{TRLV}}{V_{TRHV}}\right]^2$$

Where Z_{1RC} = System Source Impedance (Primary Ohms)
V_{SYS} = Transmission System Voltage
$I_{F\_SYS\_3H}$ = Three Phase POI Fault Magnitude
V_{TRLV} = Transformer Low Side Voltage
V_{TRHV} = Transformer High Side Voltage

For the outline example, a hydroelectric generator facility will be analyzed. The facility has ten, 100 MVA generators. For this example, we will evaluate a single generator unit as shown in Figure 6.2.

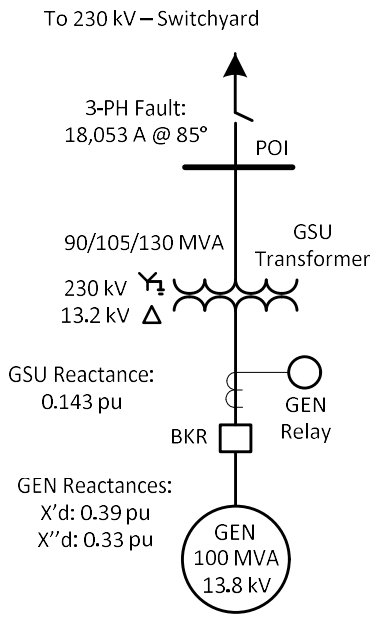

Figure 6.2 – Example Generation Facility

The protection example studied here is a numerical multi-function generator relay that includes loss-of-synchronism (ANSI 78), loss-of-field (ANSI 40) and backup distance protection (ANSI 21), but could be made up of several single-function static or electromechanical relays. All of these impedance-based elements are within the scope of PRC-026-1 and require compliance evaluation. For this example, the protection elements were found to be set based upon IEEE Standard C37.102 guidelines.

B. Unstable Power Swing Region Analysis

While PRC-026-1 allows for alternative analysis methods, such as completing a generator stability model, the following sections use the conventional R-X plot method because in the absence of a complete stability study the R-X method is the most straight-forward approach to verify compliance. The first step in applying the R-X method is to plot an unstable power swing region (UPSR) per PRC-026-1 Attachment B. It's important to note UPSR defines the boundary outside of which impedance elements could trip a BES generator for a stable power swing. Protective element R-X characteristics must plot within the UPSR unless excluded by PRC-026-1 Attachment A. The plotted UPSR from our example facility above is shown in Figure 6.3 below.

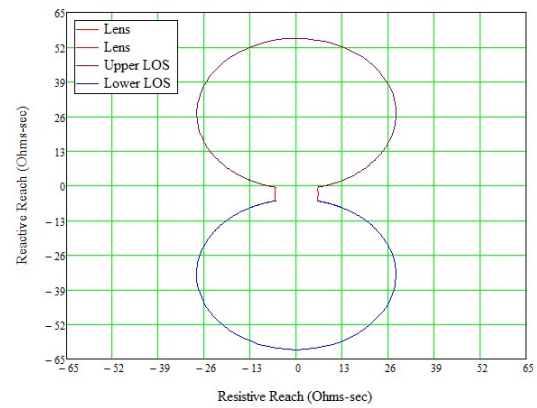

Figure 6.3 – Composite Unstable Power Swing Region

PRC-026-1 Attachment B has two separate evaluation criteria: A for impedance based elements, and B for overcurrent based elements. Both criteria require a system separation angle of at least 120 degrees to be used unless the transient stability analysis shows a reduced angle. In addition, Attachment B requires the POI impedance be determined with all generation in service and transmission elements in their normal operating switching. Because it is difficult to anticipate all worst-case power angles and swing trajectories for each contingency without performing comprehensive system stability studies by computer simulation, this methodology simplifies the analysis and produces the most conservative results.

The USPR is a composite of three separate shapes in the R-X plane shown in Figure 6.4. These shapes include Upper and Lower Loss of Synchronism Circles, and a Lens shaped that interconnects them.

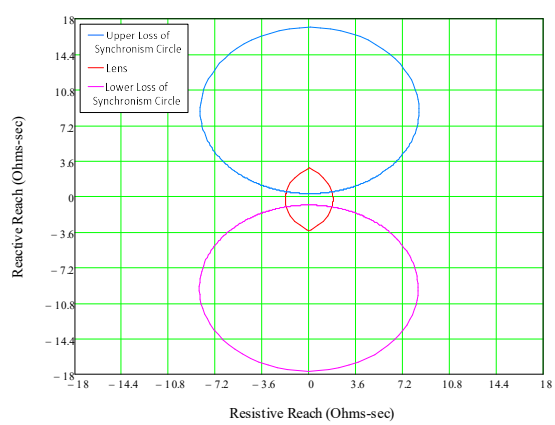

Figure 6.4 –Unstable Power Swing Region Shapes

The Lower Loss of Synchronism Circle is based on a ratio of sending-end to receiving end voltages (refer to PRC-026-1 Application Guidelines Figure 2) of:

$$\frac{E_S}{E_R} = \frac{0.7}{1.0} = 0.7$$

The Upper Loss of Synchronism Circle is based on a ratio of sending-end to receiving-end voltages:

$$\frac{E_S}{E_R} = \frac{1.0}{0.7} = 1.43$$

Internal generator voltage is non-zero during transmission faults or severe power swings due to voltage drop across the machine and GSU impedances. The sending and receiving voltage ratios are selected to be more conservative than the 0.85 pu criterion used in NERC PRC-025 and 023 relay loadability standards to include the generator internal voltage response range of +/- 15%. The criterion values shown above were based on the following per unit ratios conservatively rounded up and down to incorporate points where motor loads will stall and electromechanical contactors drop out for voltage sags during severe disturbances, [1], [3].

$$\frac{E_S}{E_R} = \frac{1.15}{0.85} = 1.353$$

$$\frac{E_S}{E_R} = \frac{0.85}{1.15} = 0.739$$

The Upper and Lower Loss of Synchronism circles are plotted based on the total system impedance. For our example generation facility, this would be the sum of: 1) the transmission system positive-sequence source impedance at the POI, 2) the GSU positive-sequence reactance, and 3) the generator sub-transient reactance, all converted to per unit.

$$Z_{SYS} = X_d'' + X_{GSU} + Z_{1RC}$$

Where Z_{1RC} = System Source Impedance (Per Unit)
X'_d = Generator Sub-transient Reactance (Per Unit)
X_{GSU} = GSU Reactance (Per Unit)

The loss of synchronism mho circles are plotted as shown in the PRC-026-1 Application Guideline Table 13 and Figures 15a to 15h. The equations below were derived from the standard so as to directly generate each point on the mho circle:

Let Ø define a range between -120° to 240°

Then define the Sending and receiving voltage ratios, allowing the E_S for upper to vary as a function of Ø.

For plotting the lower circle E_R for the lower expression would vary as a function of Ø.

$$E_{SUp}(Ø) = \frac{1.2\, V_{GEN}}{\sqrt{3}} e^{-jØ}$$

$$E_{RLow} = \frac{0.839\, V_{GEN}}{\sqrt{3}} e^{-j0}$$

Note that we have used the following ratio:

$$\frac{E_S}{E_R} = \frac{1.2/\sqrt{3}}{0.839/\sqrt{3}} = \frac{0.693}{0.484} = 1.43$$

Now we will define the ratio of the total system impedance to the generator sub-transient reactance.

$$Z_R = \frac{X_d''}{Z_{SYS}}$$

The upper loss of synchronism circle can now be plotted using the following function of Ø.

$$Z_{Up}(Ø) = \frac{(1 - Z_R)E_{SUp}(Ø) + Z_R E_{RLow}}{E_{SUp}(Ø) - E_{RLow}} Z_{SYS} Z_{base}$$

It should be noted that this expression should also be multiplied by the impedance relay instrument transformer ratio CT/VT to put the results on the same base as the relay secondary quantities; this allows the UPSR to be directly plotted with the protective element settings. If a composite characteristic of the UPSR is desired as shown in Figure 7.4, it will necessary to reduce the Ø range from -120° to 120° so each mho circle just intersects the lens characteristic.

An important observation can be made about the upper and lower loss-of- synchronism circles, in that they are derived based on the total system impedance and will change if the system impedance changes over time. This is why PRC-026-1 Requirement R2 requires re-evaluation of applicable relay elements every five years.

The Lens shape that interconnects the upper and lower UPSR mho circle shapes is intended to represent the interconnecting transmission system with a constant 120° angle between the local generator and remote system source as the sending and receiving bus voltages are varied from 0 to 1 per unit. The Lens is derived by connecting both the system impedance end points together, similar to Figure 4.10 where the system end points are bounded by an impedance circle.

Similar to Figure 4.10, the total system impedance is developed from a two-source equivalent system network. This two-source system equivalent is used as basis for PRC-026-1 analysis, with any parallel transfer impedance removed for the most conservative result. As depicted in Figure 4.10, the total system impedance represents the summation of sending-end source impedance, line impedance with thevenin equivalent parallel transfer impedance excluded, and the receiving-end source impedance. Parallel transfer impedance is removed to exclude any infeed effect, decreasing the apparent impedance as demonstrated in PRC-026-1 Application Guideline Table 10. This results in the smallest total system impedance and lens shape, and represents the system at its strongest, limiting PRC-026-1 compliant protective element reach nearest to the generator terminals.

PRC-026-1 Application Guideline Tables 2 to 7 show how to calculate the six critical lens points for the relationship between the system source impedance and the generator reactance, but the following method will generate points around the entire lens shape for plotting:

Select an array of ratios of local-to-remote source voltage between 0.7 and 1.43. Each ratio selected will generate a point to be plotted on the lens characteristic. The greater the number of ratios selected the smoother the lens characteristic plot will appear.

$$E_{S\_ARRAY} = 0.839, 0.9, 1.0, 1.1, 1.2$$

Generate a matching array of ratios in reverse order.

$$E_{R\_ARRAY} = 1.2, 1.1, 1.0, 0.9, 0.839$$

For each ratio in above defined arrays, multiply by the respective sending or receiving generator phase voltages derived from the nominal line-line voltage.

$$E_S = \frac{V_{GEN}}{\sqrt{3}}\,[E_{S_{ARRAY}}]$$

$$E_R = \frac{V_{GEN}}{\sqrt{3}}\,[E_{R_{ARRAY}}]$$

Now create a new array, to represent the left side of the lens shape by evaluating each E_S array point with the following expression. [Note the right side of the lens is derived similarly by evaluating E_S using 120°]

$$E_{240} = E_S \cos 240° + jE_S \sin 240°$$

To plot the left side of the Lens in the R-X plane, generate each point with the following expression using the pairs of E_{240} and E_R array points. [Note the right side of the lens is plotted similarly using a 120° derived array].

$$Z_{L\_LENS} = \frac{(1 - Z_R)E_{240} + Z_R E_R}{E_{240} - E_R} Z_{SYS} Z_{base}$$

It should be noted again that the resulting array of lens points should be multiplied by the impedance relay instrument transformer ratio CT/VT to put the results on the same base as the relay secondary quantities; this allows the Lens to be directly plotted with the protective element settings. Additionally, if a full lens characteristic is desired, it will necessary to widen the ratios in the E_S and E_S arrays shown in the example to evaluate points beyond the intersection with the composite UPSR characteristic.

Again, an important observation can be made about the Lens, like the UPSR shapes, it is derived based on the total system impedance and will change if the system impedance changes over time.

The following sections will discuss each of the applicable impedance based generation protection elements present in our example generation facility as shown in Figure 6.2.

Table 1 describes how generator impedance, when holding the system impedance steady affects the UPSR characteristic. Table 1 also shows similar results when the system impedance varies while holding the generator impedance steady.

Table 1: UPSR Characteristic

Value Change	Lens/Circles	UPSR Shift
Gen Z Increase	Grows	Reverse
Gen Z Decrease	Shrinks	Forward
System Z Increase	Grows	Forward
System Z Decrease	Shrinks	Reverse

Note: System Impedance includes GSU and source Impedances.

C. Loss of Field Elements

Loss of Field (LOF) protection element (ANSI-40) is commonly implemented using a two-level, reverse offset Mho impedance characteristic. The LOF element will pick up when the synchronous generator behaves like an induction generator after losing excitation drawing commutating VARS from the transmission system. The protective relay is applied at the generator terminals such that the reverse characteristic reaches though the generator. The measured generator impedance during a LOF condition will plot on the R-X plane between the generators synchronous reactance (X_d), and transient reactance (X'_d) depending upon loading.

LOF protection is typically set by the method described in IEEE Std. C37.102 [4], using two zones to accommodate both lightly loaded (time delayed Zone 2) and heavily loaded (instantaneous Zone1) generator conditions. Typical practice considers settings a mho characteristic with a diameter equal to the generator X_d reactance with the reverse offset being half the generator X'_d reactance. This conservatively extends the zone beyond the generator X_d reactance and greater than the generator X'_d reactance. The Zone 1 diameter is set to equal the machines impedance base.

To comply with PRC-026-1, Zone 1 must plot within the lower mho circle of the UPSR, but Zone 2, if set with a delay of 15 cycles or longer, is exempted from the standard. The offset used in setting both the Zone 1 & 2 elements is intended to avoid inadvertent pickup during power swings, placing both Zone 1 and 2 well outside of the Lens area of the UPSR.

Some older electromechanical LOF protection schemes combined the backup forward distance element (ANSI 21) with the LOF function by offsetting the mho characteristic origin to cover the Zone 1 area, but used a delay timer. This relay characteristic will almost certainly plot beyond the confines of the UPSR and cannot be made compliant unless the timer is set for 15 cycles or longer.

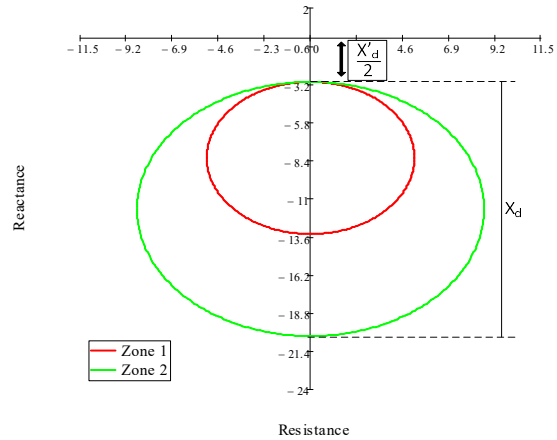

Figure 6.5 – Typical LOF Mho characteristics

Zb = Base impedance of the machine
X'd = Generator Saturated transient reactance
Xd = Generator Saturated synchronous reactance

Once the UPSR is defined per the UPSR analysis shown above, evaluating the loss of field elements for PRC-026-1 compliance is a straightforward task. Non-compliant protection characteristics are apparent by visual inspection of the plots. Figure 7.4 shows the LOF Zone 1 and 2 elements from our example system plotted with the UPSR. Since LOF Zone 1 and 2 are contained within the UPSR the element is in compliance.

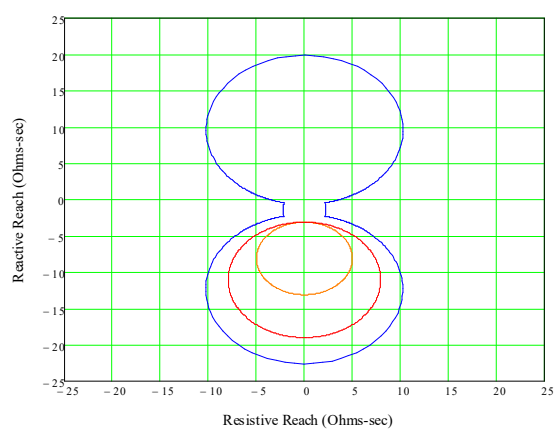

Figure 6.6 – Two Zone LOF Elements Evaluated for Compliance

D. Out of Step Elements

There are multiple methods of setting out-of-step (OOS-78) elements for traditional generator unit protection. The example uses impedance tracking with inner blinders and an outer supervisory mho characteristic, also called "single-blinder", as it is the most common method of OOS protection applied with numerical relays. Since generators and their GSU transformers typically have very high impedance when compared to the connected system equivalent source impedance, it is likely that the electrical center is near to or within the generator or GSU impedance characteristic. This necessitates out-of-step or loss of synchronism protection for the generator, as any unstable swing impedance trajectory will pass very near or though the generator or GSU. The example OOS protection method was based on IEEE Std. C37.102 guidelines, [4].

Single-blinder OOS protection typically uses a supervisory mho element set with a forward-reach of 2-3 times the generator transient reactance (X'_d) which is intended conservatively cover the generator impedance. The reverse-reach of this mho element is typically set 1.5 to 2 times the GSU reactance based on the same conservative approach. This approach assumes the single-blinder method is applied to the generator relaying looking out into the GSU and system, where the GSU impedance relatively large compared to the system source impedance beyond the GSU. This mho characteristic is shown in Figure 6.7 as the light blue trace, and can be compared to the total system impedance circle plotted in the dark blue in Figure 6.7.

The second component of the single-blinder scheme are vertical blinders (shown red in Figure 6.7). In the absence of a complete stability study for the generator and surrounding electric system, these are usually set such that they intersect the power angle at 120° either side of the resistance axis, [4], [5]. Again, this represents the angular separation between the generator rotor and the remote system equivalent source rotor at which point a power swing is unlikely to be stable.

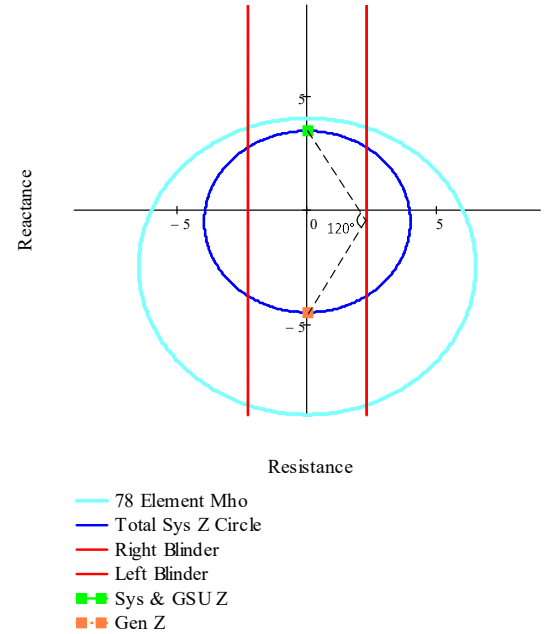

Figure 6.7: Typical Single-Binder 78 Element Characteristic

The single blinder OOS method works by tracking the apparent positive sequence impedance trajectory (system swing locus) once it enters the supervisory mho characteristic. Usually the apparent impedance falls well outside the mho circle during steady-state operation or for remote balanced faults, but the power swing locus will pass within the mho circle for both significant stable and unstable swings. The right and left blinders prevent the element from tripping the generator unless an unstable swing trajectory moves between them—either approaching from the right or left. In numerical relays, the element usually also distinguishes between a balanced system fault and an OOS condition by monitoring how quickly and abruptly the apparent impedance moves into the mho and then across the blinder characteristics. Balanced faults will immediately move to a new apparent impedance, and depending how close they are to the generator can plot to a point within mho circle, whereas power swings trajectories move more slowly along a somewhat predictable path as discussed above.

Non-compliant protection characteristics are apparent by visual inspection of the OOS elements plotted with the UPSR on the R-X diagram. For single-blinder OOS schemes, the blinder elements must plot within the UPSR to be compliant as they will initiate tripping, but the supervisory mho circle can fall outside; the outer supervisory blinders used in two-blinder OOS schemes are also allowed to fall outside the UPSR characteristic.

Figure 6.8 and 6.9 show the OOS element from our example system, set using the industry standard practices described previously along with the UPSR. Notice that the OOS blinders are not contained within the UPSR region along the lens portion of the characteristic. The 78 element is non-compliant.

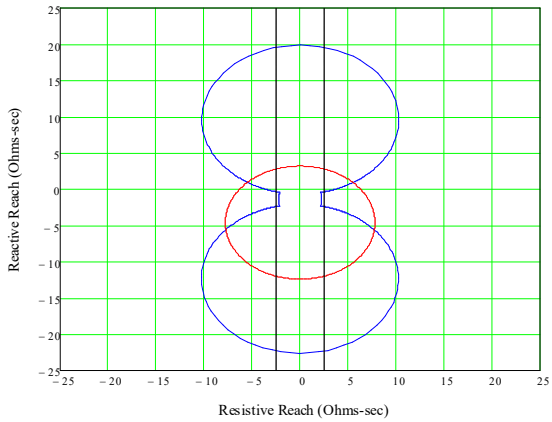

Figure 6.8: Evaluated Single-Binder 87 Element

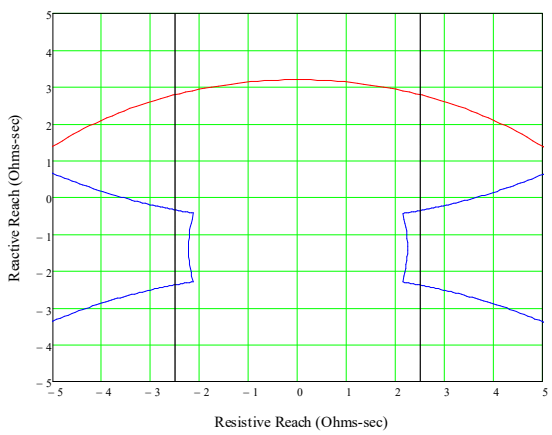

Figure 6.9: Close-Up View of Figure 6.8

E. Backup Distance Elements

Phase distance elements (ANSI 21P) are often used to provide backup for the generator, GSU and sometimes a portion of the transmission system beyond the generation facility, but their applied protective reach has been greatly limited by PRC-025-2. Primary generator and GSU protection is typically provided by high-speed differential relaying, and backup distance protection is traditionally applied to protect these valuable assets. Additionally, backup for the adjacent transmission system may be desired to isolate the generator from a transmission system fault, which does not promptly clear. While there are several types of backup elements commonly used with generators, our example system implemented a compensator mho distance scheme. The following mho distance scheme was set per IEEE Std. C37.102 guidelines, [4].

Phase distance mho elements plot on the R-X plane as a circle as shown in Figure 6.10. The impedance origin of the plot is defined by the relay's potential transformer (PT) location, typically at the generator terminals on the medium voltage side of the GSU. The mho distance element reach setting allows the element to protect a specific distance into the GSU and transmission system corresponding to these system components impedances. Similar to the OOS element mho circle, the apparent load impedance will normally plot well outside the mho characteristic on the R-X plane, with close-in transmission and GSU multi-phase faults falling within.

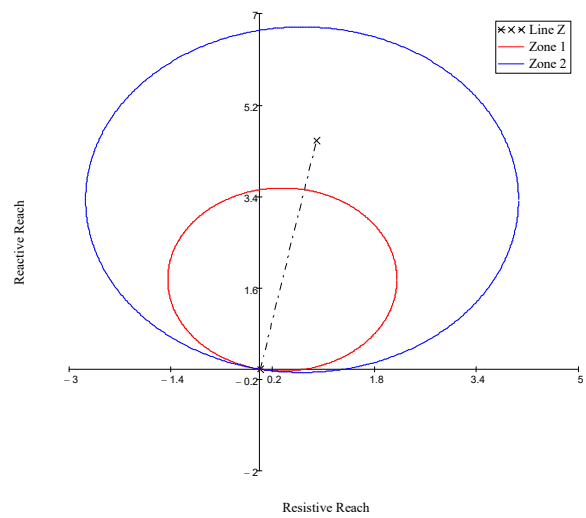

Figure 6.10: Typical Backup Distance Protection Characteristics

Many numerical generator relays allow multiple backup distance zones to be configured. It has become common to apply two zones of mho distance elements for more dynamic backup protection. The Zone 1 backup element reach is typically set to encompass the generator and part-way into the GSU with no time delay to protect from a generator or GSU differential relay failure. The Zone 2 element is set to reach slightly or significantly beyond the GSU to provide coverage for the entire generation facility and interconnect to the transmission system. The Zone 2 time delay set to allow operation of transmission system relaying and breaker failure schemes. If the Zone 2 delay is set to 15 cycles or greater, the element is excluded from PRC-026-1 compliance.

During a stable power swing, the swing locus may pass through the backup mho element(s) respective

characteristic and actuate the element, especially if the electrical center is within the GSU. For this reason, the mho characteristic should plot within the USPR unless a 15 cycles or greater time delay is applied.

Once the UPSR is defined, evaluating the backup distance elements for PRC-026-1 compliance is a straightforward task by visual inspection. Figure 6.11 shows the distance element from our example system, with the two zones set as described above and plotted with the UPSR. Since both zones of the mho distance element are contained within the UPSR, the element complies with the standard.

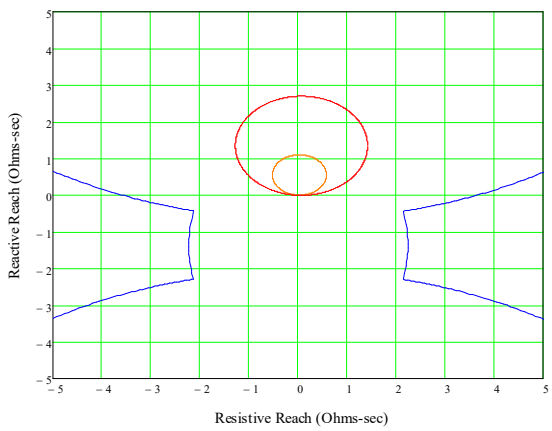

Figure 6.11: Close-Up Evaluated Distance 21 Element

F. . Mitigation and Methods Comparison

This section will discuss each applicable element in the example system shown in Figure 6.2. While only the OOS 78 element was found to be non-compliant in our example system, a comparison between IEEE Std. C37.102 settings guidelines and PRC-026-1 methods will be of interest.

The OOS element in our example system was found to be non-compliant with the blinders located outside the UPSR. Non-compliance of single-blinder OOS scheme was found to be a common occurrence for several generation facility studies, even when set by applying long accepted methodology.

Upon further inspection of these cases, OOS protection failed compliance because of one or a combination of the following:

- Generator sub-transient reactance was used to derive the USPR
- Fault contingency was applied when setting OOS
- Rounding errors were introduced
- Binders were set to intersect the power angle of 120° at the electrical center

PRC-026-1 allows the derivation of the UPSR characteristic using either the generator transient or sub-transient reactance. It is more realistic to apply the transient reactance as stable power swings occur within the transient reactance timeframe. Since the sub-transient reactance value is smaller than the transient and synchronous reactance, this will result in a smaller system impedance and therefore a smaller (more conservative) USPR. PRC-026-1 permits using the sub-transient reactance because it may be available from a short circuit model if the detailed set of generator reactances and time constants is misplaced. The non-compliant PRC-026-1 analysis in fact used the generator sub-transient reactance whereas the OOS element was originally set based upon generator transient reactance. When the UPSR was revised using the transient reactance the OOS element was close to meeting compliance as shown in Figure 6.12.

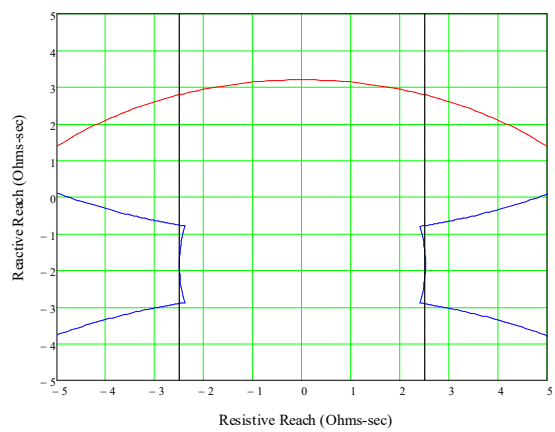

Figure 6.12: OOS Element Close-Up After Mitigation 1

The example system OOS element settings reviewed above were developed by applying a system contribution fault contingency, which placed the strongest fault contribution system element out-of-service, effectively increasing the source impedance. With increased source impedance, the OOS elements blinders may be set farther from the R-X plane origin. PRC-026-1 requires UPSR characteristic derivation to be performed with an intact system, resulting in a smaller UPSR Lens characteristic. This is likely not a significant factor in most cases, as the GSU reactance is typically much larger than system source impedance but adding contingency could make an OOS element noncompliant. For our example system, the added contingency had minimal impact as the GSU impedance dominated in developing the OOS element.

Rounding error, in conjunction with fault contingency, was also identified as a factor impeding compliance achievement. Since there are many sources of error in developing relay set points, (e.g. instrument transformer accuracy, data/calculation accuracy, relay error) often the blinder impedance settings are rounded in a fashion that adds margin. Different relay makes and models may also limit the decimal precision of the blinder set points, placing them slightly outside once compared to the UPSR Lens. For our example system OOS element the blinder set points were rounded to one decimal place for convenience. If the OOS element blinders are reevaluated at two decimal places with contingency removed Figure 6.13 now shows that the blinders are almost within the UPSR lens characteristic.

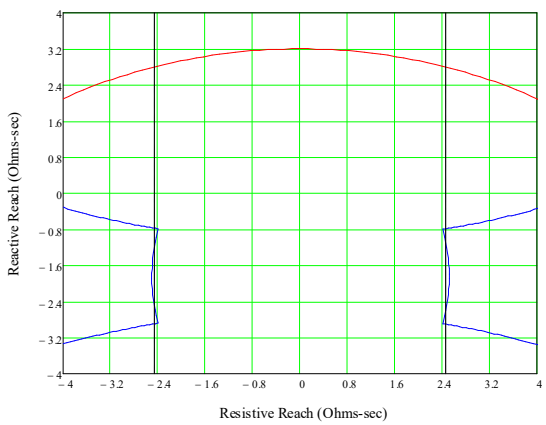

Figure 6.13: OOS Element Close-Up After Mitigation 2

The non-compliant example system OOS blinders were set to intersect the power angle of 120° about the electrical center instead of the intersection between the sending and receiving voltage sources (system impedance endpoints) which the UPSR lens characteristic uses. Once this is corrected, the result is compliant as shown in Figure 6.14.

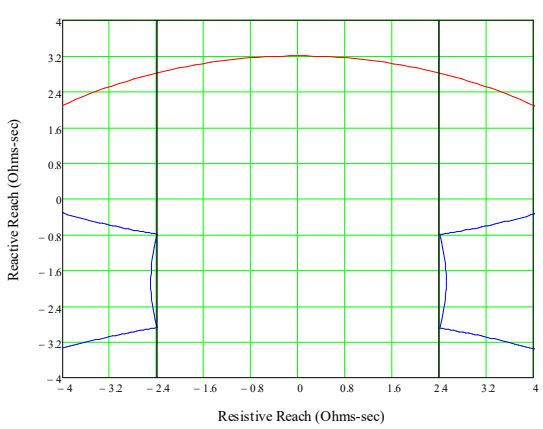

Figure 6.14: OOS Element Close-Up After Mitigation 3

Based on experience, if a generator OOS single-blinder element is set based on IEEE Std. C37.102 guidelines, the blinders likely will be very near to, but not necessarily meet PRC-026-1 compliance. This is because both PRC-026-1 and IEEE Std. C37.102 use similar but not exactly the same calculation methods and criteria. Slight blinder adjustments may be required to mitigate non-compliant OOS elements.

It should be noted that modern microprocessor relays may include OOS element algorithms for the single blinder method that require the impedance trajectory to move in the same direction, crossing both blinders before tripping is permitted. This is intended to prevent misoperation of the element for any stable swing as the system must slip a pole to actuate the element. This type of supervisory algorithm meets the stated intent and purpose of PRC-026—to prevent operation of load responsive elements for stable power swings. However, Requirement R2 of the present revision of the standard requires compliance in accordance with Attachment B using UPSR method for impedance-based load responsive elements.

While our example system LOF element was determined to be compliant by PRC-026-1 analysis, this may not always be the case. Since LOF elements are usually set per the guidelines of IEEE Std. C37.102 by using generator reactance parameters only, and PRC-026-1 applies additional impedances when developing the UPSR, applications where GSU reactance is smaller relative to the generator and/or a very low systems source impedance exists, an appropriately set LOF element may not necessarily comply with PRC-026-1. When a large steam turbine generator facility was evaluated for PRC-026-1 compliance, the result is shown Figure 6.15.

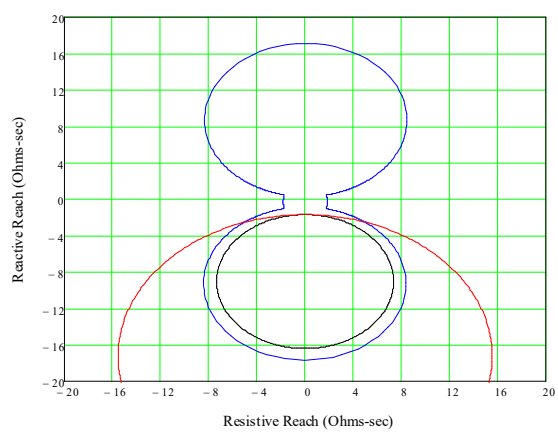

Figure 6.15: Steam Turbine LOF vs. Corresponding UPSR

Upon first inspection, the larger Zone 2 mho characteristic is not contained within the UPSR and appears to be non-compliant. However, the Zone 2 element time delay is greater than 15 cycles and therefore meets the criteria outlined in PRC-026-1 Attachment B. In this example, the GSU impedance is much larger relative to the system source impedance, but if the GSU rating were significantly larger than the generator, such as when it is sized to serve multiple machines, the high-speed zone 1 LOF element would exceed the UPSR characteristic. In such cases, it may be necessary to reduce the diameter of the high-speed zone and accept the potential of greater disconnection time delay as a tradeoff for improved stable swing security.

Phase distance elements reaches are set based upon the power system components to be protected. This is particularly true when the distance relays are applied to the generator terminals, as in our example system. Since a typically set two-zone backup distance high-speed Zone 1 element should not reach beyond the GSU it's unlikely that this element will ever exceed the UPSR characteristic as the upper-loss-of synchronism characteristic is based upon the forward system impedance dominated by the GSU. However, the longer reaching Zone 2 may extend beyond the UPSR characteristic depending upon the backup zone coverage required. In these cases the most straightforward mitigation method is to insure the zone 2 element time delay to 15 cycles or greater.

In addition to the mitigation methods mentioned previously, other common options to insure PRC-026-1 protective element compliance include but are not limited to supervised blocking, and voltage/failure supervision. Refer to Attachment A of PRC-026-1 for the complete list. Aside from increasing the time delay many of the exclusion criteria will not apply to the impedance-based element.

VII. Conclusion

As the bulk electric system evolves, it is becoming increasingly intricate which creates new reliability challenges that will need to be addressed. NERC PRC-026 takes effort to address the most plausible and potentially most critical cases of stability misoperation, while maintaining an overall objective to avoid unnecessarily burdening GOs and TOs with broad compliance requirements. While PRC-026-1 protection requirements do not necessarily need to be performed for all BES facilities—consideration of them when developing protective relay settings will increase security for severe stable power swings and preempt future compliance requirement.

PRC-026-1 protection compliance may need to be re-evaluated as the power system and protective relaying technology evolves. Future revisions of the standard might take into consideration or acknowledge supervisory algorithms built into modern relays elements. System source strength is likely to change over time as generation, load, or transmission infrastructure grow. Protective settings, which initially may be compliant under PRC-026-1 requirements, have the potential to become non-complaint in the future. Considering the potential for compliance to change, the standard makes an effort to encourage information sharing between transmission planners and asset owners as well as taking reasonable considerations in identifying what assets would likely be affected by the undesired system conditions.

VIII. References

[1] NERC PRC-026-1 *"Relay Performance During Stable Power Swings",* North American Electric Reliability Corporation, Version 1, March 17, 2016

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[4] IEEE Standard C37.102-2006 "*IEEE Guide for AC Generator Protection*", The Institute of Electrical and Electronics Engineers, Inc., 2007. ISBN: 978-0-7381-5250-9

[5] "*Protective Relaying for Power Generation Systems*", Donald Reimert, 2006, ISBN: 0-8247-0700-1

[6] "*Technical Analysis of the August 14, 2003, Blackout: What Happened, Why, and What Did We Learn?*", North American Electrical Reliability Corporation, July 13, 2004.

[7] NERC PRC-025-2 "*Generator Relay Loadability*", North American Electric Reliability Corporation, Version 2, May 2, 2018

IX. Biographies

Matt Horvath, P.E. joined POWER Engineers in 2011. He is a member of the SCADA and Analytical Services group where he performs a variety of electrical system studies for transmission, substation, and generation projects. He has a background in protective relaying, transmission system coordination, power system analysis, arc flash analysis, NERC reliability standards, and grounding grid analysis. Matt holds a B.S. in electrical engineering from Washington State University and is a registered professional engineer in Washington and Texas.

Matthew Manley joined POWER Engineers in 2015. He is a member of the SCADA and Analytical Services group where he performs a variety of electrical system studies for transmission, substation, and generation projects. He has a background in protective relaying, transmission system coordination, NERC reliability standards, and soil resistivity testing and grounding grid analysis. Matt received his B.S. in electrical engineering from Texas A&M University.