Stability Studies For System Dependent Generator Protection Functions

Prem Kumar, *Senior Member, IEEE*, Dale Fredrickson, *Member, IEEE,* Koushik Chanda, *Member, IEEE*

***Abstract*— The blackout of August 2003 caused misoperation of several system dependent protections of generators during the disturbance, exacerbating an already bad grid situation. Since then, there is increasing scrutiny on generator protection. The need to verify the operation of system dependent generator protection functions during system power swings is becoming increasingly important. Stability studies are needed to verify the impedance locus and expected relay operations for the various cases of power swings. In today's deregulated energy market stability studies are typically performed by planning engineers of the transmission company or their consultants, and generator protection studies are performed by the protection engineers of the generating company or their consultants. Both studies are generally difficult to perform because of the amount of data required, different entities involved, and availability of engineers with a combined understanding of stability and protection. This paper will provide a basic overview of stability studies and system dependent protection functions, will identify the required generation and transmission system parameters, present guidelines to perform a comprehensive study through an actual example, and will assist the generation and transmission engineers to achieve the desired result for system dependent generator protection functions.**

***Index Terms*-Stability study, protection, relays, out of step, system disturbances, loss of field, distance protection.**

I. INTRODUCTION

Bechtel was contracted to design/build two supercritical generating units at Elm Road Generating Station (ERGS) in Oak Creek, WI for We Energies. The two generating units (Units 1 and 2) tie into an existing 345 kV system through their respective Generator Step Up (GSU) transformers. A simplified sketch of a single unit is shown in Fig. 1. One of the engineering efforts for this project required setting the generator protection relays. The generators were protected by two independent microprocessor relays. Stability studies were performed to verify the protective settings for system dependent generator protection, functions, i.e. out of step protection, loss of field protection and distance protection. This paper outlines some basic concepts of stability, the steps and inputs needed for stability studies to be done by the transmission planning engineers, and the specific outputs needed for the generation protection engineers for correctly setting the system dependent protections.

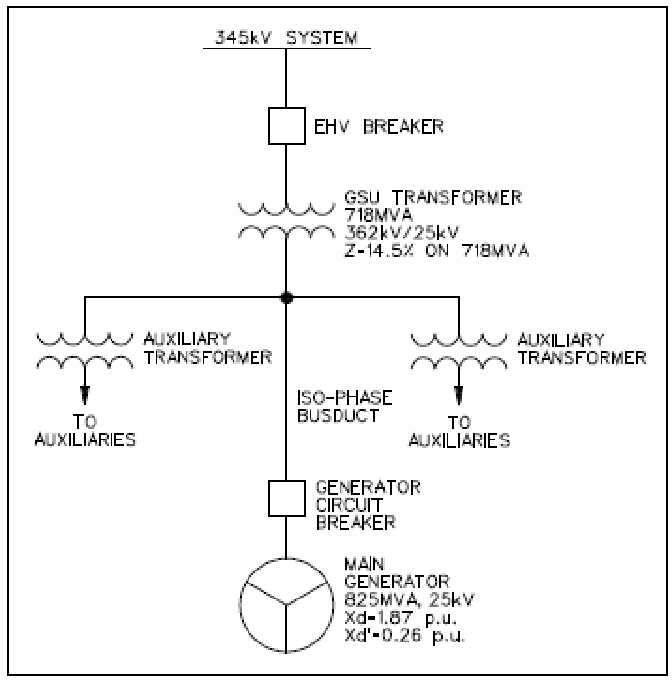

Figure 1: One Line Representation of the Generating Power Plant

II. BASIC OVERVIEW OF STABILITY STUDY

Power system stability is defined as the property of a power system that enables it to remain in a state of equilibrium under normal operating conditions and to regain an acceptable state after being subjected to a disturbance. Concepts covered in this overview are the swing equation, power transfer equation, and machine/ load parameters that play significant roles in stability studies.

The swing equation governs the motion of the generator rotor relating the inertia torque to the resultant of electric and mechanical torques on the rotor.

$$J(d\omega_r/dt) = T_a = T_m - T_e \qquad \text{----- (1) [1, 2]}$$

This can be converted to power in pu and inertia constant

$(2H/\omega_r)\, d^2\delta / dt^2 = P_m - P_e$ ---- (2) [1, 2]

$P_e = P_{max} \sin\delta$ ---- (3) [1, 2]

Where
J = Moment of inertia of turbine-generator kg –m
H= inertia constant in seconds
δ = electrical angle between generator and system in radians
ω_r =Angular velocity of rotor, mech rad/s
T_a = Accelerating torque in N-m
T_m = Mechanical torque N-m
T_e = Electrical torque N-m
P_m = Mechanical power in pu
P_e = Electrical power in pu
P_{max}= Maximum electrical power

During normal conditions, the mechanical torque (based on steam input to the turbine) applied to the generator rotor shaft produces electric power output from the generator. Based on the actual electrical load demand, the system provides a balancing electrical torque. In steady state, the rotor therefore runs at a constant speed with this balance of electric and mechanical torques. .Any unbalance between the generation and load causes a transient that would cause the rotor of the synchronous machines to "swing" because of net accelerating or decelerating torques exerted on these rotors as shown in equation 1. Reduction in electrical load demand tends to accelerate the machine. Increase in load demand tends to decelerate the machine, requiring increased mechanical torque and power to balance. Considering an abnormal condition such as when a fault occurs, the amount of power transferred is reduced (because of reduced electrical load) and therefore the electrical torque that counters the mechanical torque is reduced. If the mechanical power is not reduced during the period of the fault, the generator rotor will accelerate proportionally to the net surplus of torque input. Consequentially an unstable condition exists in the power system, one equivalent generator rotates at a speed that is different from the other equivalent generator of the system. Such a condition is referred to as a loss of synchronism or an out-of-step condition of the power system.

Small-signal stability is the ability of the power system to remain in synchronism under small disturbances. These occur continuously in the form of variations in load and generation. Transient stability is the ability of the power system to maintain synchronism when subjected to severe transient disturbance. The resulting system response involves large excursions of generator rotor angles.

The steady state power transfer stability limit is determined by the power transfer equation. The power transfer equation for a simple loss-less line is shown in equation 4 and is plotted graphically in Fig. 2.

$$P_e = \frac{E_g . E_s}{X} \sin(\theta_g - \theta_s) \quad \text{---- (4) [1, 2]}$$

Where: E_g = Voltage at Generation
E_s = Voltage at System
P_e = Electrical Real Power Transfer

X = Steady State Reactance Between Generator and System
θ_g = Voltage Angle at Generation
θ_s = Voltage Angle at System

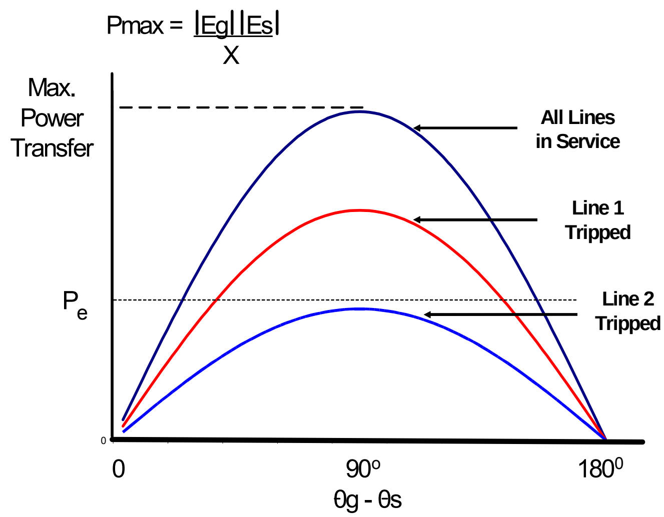

Figure 2: Power Angle Analysis - Steady State Instability

From the power transfer equation above it can be seen that the maximum power (P_{max}) can be transmitted when θ_g-θ_s = 90^0. The electrical power from the swing equation as a function of internal electrical angle is $P_{max}\sin\delta$ (equation 3). When the voltage phase angle between local and remote generation increases beyond 90^0 'the power that can be transmitted is reduced and the system becomes unstable and usually splits apart into islands. For clearing a fault, one or more lines are tripped between the load center and remote generation supplying the load center. As a result, the reactance (X) between these two sources increases, resulting in an adjusted maximum power (P_{max}) corresponding to the new reactance (X). If the magnitude of this adjusted Pmax falls to a value lower than pre-fault operating power Pe, then it is insufficient to maintain synchronism, and as a result stability is lost. The power angle curve in Fig. 2 illustrates this reduction of maximum power. As line 1 trips the height of the power angle curve and maximum power transfer is reduced because the reactance (X) has increased. When line 2 trips the height of the power angle curve is reduced further to the point where the power being transferred cannot be maintained and the unit goes unstable.

Machine parameters that play an important role in transient stability are machine inertial constants and excitation systems. In the swing equation (2) these are H and Pe (excitation system impacts P_e). Improved cooling methods in modern generators have allowed larger kVA capacities for a given volume of materials, reducing inertia constant (H) and increasing machine reactances. The excitation system of a generator provides the energy for the magnetic field that keeps the generator in synchronism with the power system. The most commonly used voltage control mode for generators of significant size that are connected to a power system is the Automatic Voltage Regulator (AVR) mode. In this mode the excitation system helps to maintain power system voltage within acceptable limits by supplying or absorbing reactive power as required. In disturbances where a fault depresses the system voltage, electrical power cannot fully be delivered to the transmission system. Fast response of the AVR and excitation system helps to increase the synchronizing torque to allow the generator to remain in synchronism with the system. This concept can be illustrated with an example of a three phase solid fault at the load. In this situation Es=0, and so the electrical power Pe during the fault is zero (from Equation 4). Since the turbine control cannot instantaneously reduce its power output, the power that was previously delivered as input to the load now accelerates the combined rotating mass of both the generator and turbine rotors (see Equation 2). This causes angle delta to increase. The excitation, in response to the reduced terminal voltage, increases its voltage output to ceiling, causing the internal voltage (E) of the generator to increase at a rate determined by the operating time constant of the field and the ceiling voltage. Assuming that a generator trip has not occurred, the load voltage is restored when the fault clears. The new internal voltage and the new angle delta (θ_g-θ_s) now determine the electrical power delivered to the load, following equation 4. This new electrical power must be larger than the mechanical power input from the turbine in order that the kinetic energy gained by the rotor during the fault is removed causing the rotor to decelerate. If the "new electrical power" is less than the mechanical power, the rotor will continue to accelerate and the generator will lose synchronism. Exciters with high ceiling voltages and fast response times help the internal voltage of the machine to increase rapidly, increasing the new electric power, and thus increasing the probability that the kinetic energy gained during the fault will be removed from the rotor. If this energy is not removed the generator will lose synchronism and a subsequent trip will result.

Since the excitation system plays a critical role in transient stability studies, it is very important to completely model the excitation system for the stability studies. Power system stabilizers (PSS) are supplemental controllers designed to dampen power swings, and should also be modeled. Power system stabilizers are most effective to enhance small signal stability where there is insufficient damping of system oscillations. Fast acting excitation systems, though beneficial during the fault, can exacerbate power swings immediately after the fault. PSS's can modulate the exciter response in that period. However, PSS's are generally ineffective in averting first swing stability.

More rigorous stability studies require an accurate static and dynamic load modeling to capture the load characteristics correctly. The voltage and frequency sensitivity for static load models would be required. Dynamic load models would require higher order motor models [3].

It is also important to understand how a system of multiple generators responds to a temporary unbalance of generation and load, as typically happens in any power system, resulting in power swings. An unbalance could be due to loss of generation, loss of load, addition of load, or faults on the system. Transient stability studies are generally needed to model behavior during faults and the post-fault period. At any time generation must match load plus transmission losses plus interchange. Considering a fault that causes a generator to be lost, the immediate replacement generation power comes from generators electrically closest to the affected load centers. Consequently, as those generators slow down, and frequency drops, inertia arrests frequency decay, causing electrical redistribution of power by the relative inertia values of the various generators in the system. This "inertial power flow" is irrespective of electrical closeness of the generators. At roughly the same time, governor controls respond to decaying speed and open steam turbine valves within 3- 5 seconds, causing "governor power flow". The Automatic Generation Control (AGC) becomes active from 10 seconds to minutes time frame with "AGC power flow" and restores the frequency**.** Therefore for the above case there are at least four load flows in the system as the generators and loads in system are changing during the transient (from inception of fault up to 10 seconds after clearing of fault)**.** These varying power flows manifest themselves as power swings in the interconnected system. Power swings are variations in power flow in a system when the generator rotor angles are changing relative to one another in response to unbalance of generation and load. Most power swings do not cause generator instability. Transient stability studies are typically done for a span of several seconds.

III. OVERVIEW OF SYSTEM DEPENDENT PROTECTION

Of the various generator protection elements, distance protection (21), loss of field protection (40), and out of step protection (78) are impedance based. These functions will see a movement of the impedance locus during a power swing. The goal is to ensure that these system dependent protections do not mis-operate during stable power swings, and that out of step protection correctly operates in case of unstable swings. This section will briefly discuss these three protections. There are various setting criteria for these three protections as outlined in detail in Reference 7. The settings discussion in this section will only discuss the criteria used for the ERGS project.

The purpose of the **Distance (21)** protection is to protect the generator from supplying prolonged fault current to a fault on the power system to which the generator is connected. It is generator backup protection to the system protection. A mho characteristic is commonly used (see Figure 3) to detect system phase faults and to disconnect the generator after a set time delay. Faults in the transmission system should generally be cleared by system relays. Therefore this protection must be coordinated with system relays and will act if the system relay(s) fail.

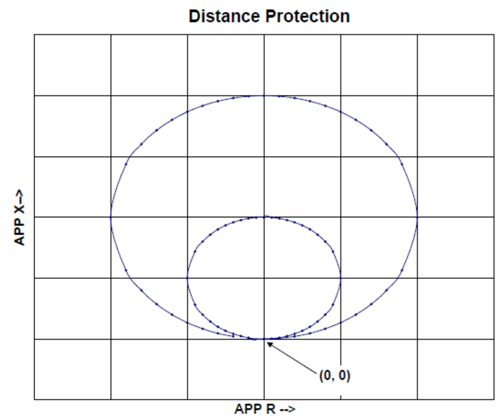

Figure 3: Typical Distance Protection

For the specific case under discussion, a two step mho protection was used for distance protection. Zone 1 of the distance relay was set to half the generator step up (GSU) transformer impedance with a time delay of 0.25 seconds. This was intended as a backup protection for faults in the isolated phase bus duct (IPB). Zone 2 of the distance relay was set beyond the GSU transformer with 1.2 times the line impedance of the 345 kV line between the GSU and the Switchyard (see Figure 1). The zone 2 timer was set to 1 second. System stability studies should verify the adequacy of the timer settings.

The purpose of Loss of Field (40) protection is to detect a complete or partial loss of field. Loss of field on a synchronous generator is detrimental to both the generator and the power system to which it is connected. When the generator loses its field, it operates as an induction generator, causing the rotor temperature to rapidly increase due to the induced eddy currents in the rotor iron caused by slip. The high reactive current drawn by the generator from the power system can overload the stator windings, and the stator end-iron damage limit may also be exceeded.

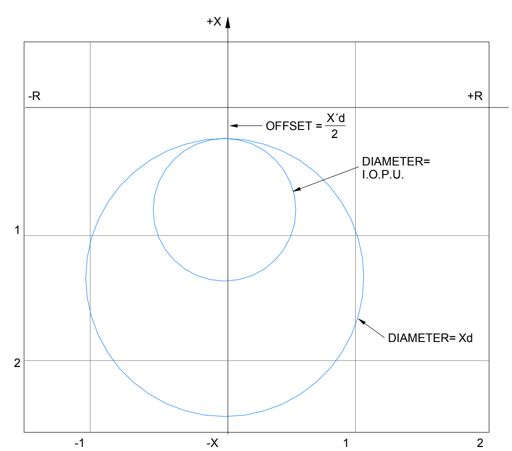

Figure 4: Negative offset loss of field

The most widely applied method for detecting a generator loss of field condition on major generators is the use of distance relays to sense the variation of impedance as viewed from the generator terminals. A two-zone distance relay approach is widely used within the industry to provide high-speed detection. The relays are applied at generator terminals and set to look into the machine. There are two methods used in the industry. One uses a negative offset mho, and the other uses a positive offset mho. The negative offset mho method was used for this specific project as shown in Figure 4. The smaller mho has a diameter of 1 pu (generator base impedance) and the larger mho has a diameter of Xd (synchronous impedance). Both mho circles will have an offset of half of transient reactance (X'_d). For the ERGS project the smaller mho had a time delay of 0.1 second and the larger mho a time delay of 0.5 second. Stability studies should verify the adequacy of these timer settings. Unstable power swings may cause operation of loss of field relays. This may or may not be acceptable, although usually not desirable since it is not the intended function of a loss of field relay.

The purpose of **Out of Step (78)** protection is to protect the machine if it loses synchronism with the power system. When a generator loses synchronism, the resulting high peak currents and off-frequency operation can cause winding stresses, high rotor iron currents, pulsating torques and mechanical resonances that are potentially damaging to the machine. To minimize damage the generator should be tripped without delay, preferably on the first slip cycle. During an out-of step (OOS) condition the apparent impedance, as viewed from the generator terminals, will vary as a function of system and generator voltages and the angular separation between them. The impedance locus will depend on the excitation system, machine loading and initiating disturbance. Typical out of step impedance loci are shown in Figure 5.

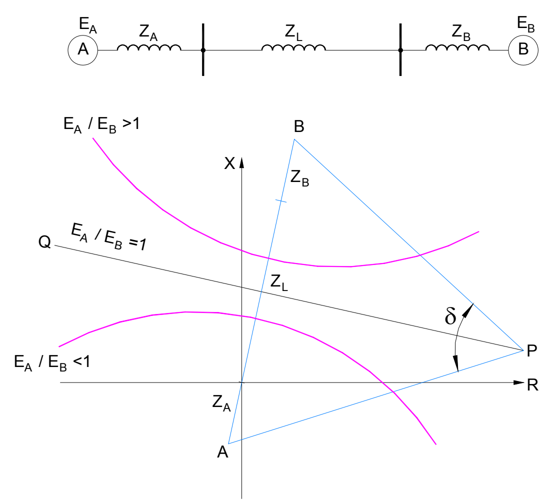

Figure 5: Typical Out-of-Step Impedance Loci

E_A and E_B represent the voltages of system and generator. When the voltage ratio of $E_A/E_B = 1$, the impedance locus is a straight line indicated by PQ, which is the perpendicular bisector of the total system impedance between A and B. The angle formed by the intersection of lines AP and BP on line PQ is the angle of separation δ between systems. As E_A advances in angle ahead of E_B the impedance locus moves from point P toward Q and the angle δ increases. When the locus intersects the total impedance line AB, the systems are

180° out of phase. This point is the electrical center of the system and represents a three-phase apparent fault at that impedance location. This is the point where the apparent voltage of the system as seen by the generator is zero during an unstable swing. As the locus moves to the left of the system impedance line, the angular separation increases beyond 180° and eventually the systems will be in phase once again. If the systems remain together, system A can continue to move ahead of system B and the whole cycle may repeat itself (multiple slips). When the locus reaches the point where the swing started, one slip cycle has been completed. If system A slows down with respect to system B, the impedance locus will move in the opposite direction from Q to P. When the voltage ratio E_A/E_B is greater than one, the electrical center will be above the impedance center of the system (line PQ). When E_A/E_B is less than one, the electrical center will be below the impedance center of the system.

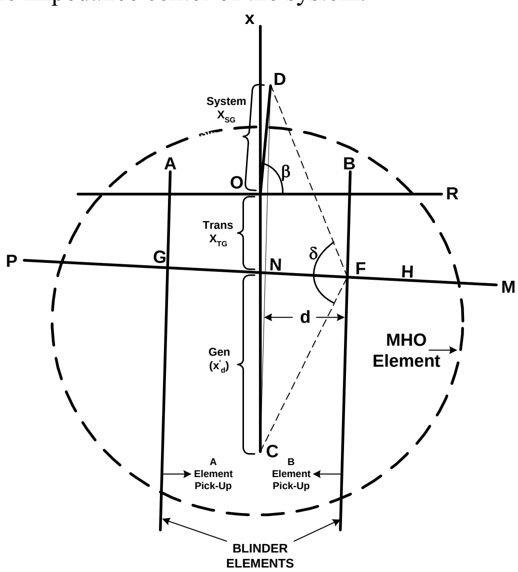

Figure 6: Single Blinder Scheme

The single blinder protection method was used for out-of-step protection for this specific project (Figure 6 above). The maximum angular separation between the machine internal generator voltage and the system for recoverable swings was set as 120° (swing angle corresponding to critical clearing time that will be verified from stability studies). The diameter of the mho circle is $2X'_d + 1.5\ X_{TG}$ (where X'_d is generator transient reactance and X_{TG} is transformer impedance). The offset is $1.5X_{TG}$ (looking into system) and the forward reach (looking into generator) is $2X'_d$. From these the blinder distance 'd' can be obtained by geometry.

$$d = \left\{ \left[\frac{X'd + X_{TG} + Xs}{2} \right] x \tan(90 - \delta/2) \right\} \text{..........(5)....[7]}$$

These settings would permit tripping for impedance loci that appear in the region between the high voltage terminals of transformer down to the generator. In the figure 6 A and B are the blinders and MP is the theoretical impedance locus for a power swing. An OOS condition is when locus spends some definite time in the 3 regions (MF, FG and GP in figure 6 above).

System transient studies will plot the system impedance swing locus versus time for different scenarios to verify the settings for this system dependent protection. The criteria for a correct setting of out of step protection are that it will not trip for any stable power swing, but will trip if the swing is unstable.

IV. STABILITY/PROTECTION INTERFACE ISSUES

The following are important items that the protection engineer (generation company) would need to communicate to the planning engineer (transmission company). These are:

a) Ensure the use of complete machine data (generator, exciter, PSS, governor) and GSU data.

b) Specify kind of outputs needed from the stability study.

c) Jointly determine the cases to be analyzed.

d) The protection engineer then needs to superimpose relay curves on the stability study R-X plots and interpret the results.

Stability study software programs use higher order generator models that require various generator impedances and time constants. These data are generally available from suppliers in the form of comprehensive generator data sheets. Machine inertia data should include both turbine and generator rotors. Sometimes suppliers incorrectly provide only the turbine inertia. The other important data are generator exciter data and power system stabilizer (PSS) data such as gains and time constants for the transfer function blocks. Care must be taken to request and obtain the data from the supplier in the required format as specified in IEEE 421-5 [8]. Most stability software programs can readily use the data in this format.

The second step would be specifying the kinds of outputs required for the stability studies. For out-of-step protection, the key plots needed from a stability study for settings are:

a) Generator slip (rotor angle) vs. time. From this and 'c' below, maximum generator slip for unstable swing can be calculated

b) Characteristic of stable swing(s) in the form of impedance loci. Some should be at the critical clearing time, which will help determining the critical angle.

c) Characteristic of unstable swing(s) in the form of impedance loci.

These impedance loci should be determined for various machine configurations. The generator slip is a function of generator inertia, accelerating torques and fault clearing times. The lower the inertia, the higher the slip. The above impedance loci for stable and unstable swings will also be used for verifying settings of out of step, loss of field and distance relays.

The third step would be to jointly develop between the generation and transmission engineers the cases to be studied.

This involves engineering judgment, as only a finite number of cases can be studied. An experienced transmission engineer on a given power system will have a good idea about required system loading and the critical lines, in order to create faults that can cause the most severe impact on the given generator. Determining a representative set of cases is very important. This could be time consuming as it may be iterative. Based on evaluating the results from the first set of cases another set of cases may need to be developed. The objective of running the cases is to get the critical clearing times for the various cases and corresponding impedance loci for the various cases at critical clearing time, and just above critical clearing time when machine goes unstable. Determining the critical clearing time is a time consuming part of the stability study runs. To achieve the objective, several runs of the transient stability study are required to be performed to determine when the generator loses synchronism or undergoes the first slip. The time period for the transient stability study is typically about one and half seconds to two seconds following the fault.

For this project, for each scenario, the cases were run for each fault location, with stable cases, critically stable cases (cases at critical clearing times) and unstable cases. Also some scenarios had the generator running at lagging, leading or unity power factor. Some scenarios had the voltage regulator in and some had them out. The following fault locations for the above cases were studied:

a) At the HV terminals of the generator step up transformer

b) On the outgoing 345 kV lines that carry the most power

c) At adjoining generating station bus (physically close by, though electrically further because of transformations to 230 kV).

The final step would be to superimpose on the stability study R-X plot with the generator settings for the impedance relays. It is important to understand that the relay settings, typically provided in secondary quantities either in ohms or pu, would have to be converted to the same base as shown in the stability curves. This conversion is required for each of the system dependent protective functions. For this project they were converted to primary per unit values on 100 MVA base. A sample of the parameters to plot the relay curves in the impedance locus R-X plane is shown below.

Table 1: Distance Relay Characteristic on 100 MVA Base

Parameter	**Generator Base (825 MVA)**	**Per unit in 100 MVA base**
Zone 1 reach	$0.5\ X_T = 0.145/2$ pu on 718 MVA	0.010097 pu
Zone 2 reach	0.1275548 ohms on 25 kV	0.0204 pu

Table 2: Loss of Field Relay Characteristic on 100 MVA Base

Parameter	**Generator Base (825 MVA)**	**Per unit in 100 MVA base**
Offset	$-0.5\ X_d' = -0.26/2$ pu	-0.015 pu
Small diameter	1 pu	0.1212 pu
Large diameter	$X_d = 1.87$ pu	0.2266 pu

Table 3: Out of Step Relay Characteristic in 100 MVA Base

Parameter	**Generator Base (825 MVA)**	**Per unit in 100 MVA Base**
Forward reach	$2X_d = 0.26*2$ on 825 MVA	0.063 pu
Reverse reach	$1.5X_{TG} = 1.5 * 0.145$ on 718 MVA	0.03029 pu
Blinder setting Corresponding to system MVA 9859	$D = (X_d' + X_{TG} + X_s)/2 * \tan(90-120/2)$.	D = 0.0178 pu

V. ERGS STUDY RESULTS

The two main plots that need to be understood from the stability study are the rotor angle plot and the impedance plot. Transmission engineers are most familiar with the former, whereas the protection engineers need the second to set the relay. Both are interpreting the same event in different ways. The generator ratings as shown in Figure 1 were 25 kV, 825 MVA, with synchronous reactance of 1.87 pu and transient reactance of 0.26 pu.

a. Discussion of Stability Study Simulation :

A duration of 1.5 seconds was considered for this stability simulation. The system was considered to be in steady state for a pre-fault duration of 0.1 seconds. The rotor angle is constant at 27 degrees for the pre-fault duration. A pre-fault load impedance of 0.14 pu corresponded to 650MW of exported power at unity pf on 100 MVA base. This load point is the point P in Figure 5 showing typical out-of-step impedance loci. Both rotor angle and impedance locus are constant for pre-fault steady state. It is interesting to note that the rotor angle moves continuously in the span of simulated duration of fault. However, the impedance loci jumps from load value to the fault impedance value at fault instant and remains at a fixed point (for balanced faults) at the fault impedance value for the entire duration of fault. In the post-fault scenario both the rotor angle and the impedance locus move continuously until reaching the next stable state or it goes unstable.

The following cases were selected to be performed as shown below in Table 4. Net MW and pf values shown at 345 kV interface. The fault point locations shown in table 4 below need to be read in conjunction with figure 1. EL-RC is an outgoing 345 kV line from the switchyard. U2 is the adjoining identical unit feeding the 345 kV system. U8 is an existing generating station at the same location but feeding the 230 kV system.

Table 4-Case Description

Case#	Net MW	Power Factor	AVR	Stability	Clearing Time (cycles)	Fault Point
C1.1	650	0.98 lag	in	stable	10.0	EL-RC flt
C1.2	650	0.98 lag	in	unstable	10.5	EL-RC flt
C2.1	650	0.98 lag	out	stable	10.0	EL-RC flt
C2.2	650	0.98 lag	out	stable	10.5	EL-RC flt
C2.3	650	0.98 lag	out	unstable	11.0	EL-RC flt
C3.1	650	unity	in	stable	8.0	EL-RC flt
C3.2	650	unity	in	stable	8.5	EL-RC flt
C3.3	650	unity	in	unstable	9.0	EL-RC flt
C4.1	650	unity	out	stable	8.0	EL-RC flt
C4.2	650	unity	out	stable	8.5	EL-RC flt
C4.3	650	unity	out	unstable	9.0	EL-RC flt
C5.1	650	0.98 lag	in	stable	5.0	U2 GSU
C5.2	650	0.98 lag	in	stable	10.0	U2 GSU
C6.1	650	0.98 lag	in	stable	5.0	U8 GSU
C6.2	650	0.98 lag	in	stable	10.0	U8 GSU
C7.1	650	0.98 lag	in	stable	100.0	U2 25 kV

For cases 1 through 4 faults had been considered on a 345 kV line for four cycles, followed by a breaker failure condition. The time for critical clearing varied from about 8 to 11 cycles depending on case considered, such as AVR in, AVR out, lagging or unity pf etc. Cases where faults cleared at critical clearing time are marginally stable. Cases where faults cleared at a time greater than critical clearing time are unstable cases. Cases 2 through 4 had one stable case, one marginally stable case and one unstable case as sub cases. Case 5 considered fault on unit 2 ERGS GSU transformer high side (5 cycle and 10 cycle fault) with rotor angle and impedance locus observed from unit 1 side. Case 6 considered a fault on existing Unit 8 (5 and 10 cycle fault). Case 7 considered a fault on 25 kV side of one GSU transformer which would cause the other ERGS machine to swing.

The selection of the most representative cases, fault locations and required system loading conditions would typically be done by the planning engineer based on experience from previous stability studies. Cases 1 through 4 covered such representative cases. Some Cases such as 5, 6 and 7 were based on input from protection engineer. Case 5 was selected to simulate fault at GSU terminals. Case 6 was selected to simulate a fault at the closest generating station. Case 7 was selected to determine the maximum 25 kV breaker failure settings.

b. <u>Critical angle and maximum slip values:</u>

Correlation between the rotor angle and R-X values can be obtained from the time, angle and R-X values that are available from the stability study results. A sample from case 2.2 for a time duration from pre-fault to post-fault is shown below.

Table 5- Sample Case 2.2: Time, Angle, R and X

Time	Angle Unit 1	APP R	APP X
-0.0083	27.223	0.14094	2.12E-02
0.0292	27.223	0.14094	2.12E-02
0.0667	27.223	0.14094	2.12E-02
0.1	**27.223**	**0.14094**	**2.12E-02**
0.1	**27.223**	**4.20E-04**	**2.02E-02**
0.1042	27.223	4.20E-04	2.02E-02
0.1083	27.269	4.20E-04	2.02E-02
0.1125	27.378	4.20E-04	2.02E-02
0.1167	27.523	4.20E-04	2.02E-02
0.1208	27.711	4.20E-04	2.02E-02
0.125	27.94	4.20E-04	2.02E-02
0.1292	28.21	4.20E-04	2.02E-02
0.1333	28.523	4.20E-04	2.02E-02
0.1375	28.878	4.20E-04	2.02E-02
0.1417	29.275	4.20E-04	2.02E-02
0.1458	29.713	4.20E-04	2.02E-02
0.15	30.194	4.20E-04	2.02E-02

Next step is to obtain the critical angle and the maximum generator slip from the different cases. These values would be required for protection settings. As mentioned earlier, the initial rotor angle (δ) was 27 degrees. Subsequent step is to obtain the time for the rotor angle to go from the critical angle to 180 degrees for the unstable cases. It may be noted that the critical angle will vary slightly for the various cases. The time for the fastest unstable swing should be obtained by analyzing the data for various cases. The fastest time from the critical angle to the 180 degrees will be the minimum time for a slip.

Table 6 Maximum generator slip

Case	Critical Clearing Angle	Time for Critical Clearing Angle to 180 Degrees	Remarks
1.1	112		
1.2		0.94	
2.2	around125		
2.3		0.4	Fastest swing
3.2	113		
3.3		0.92	
4.2	118		
4.3		0.58	

The critical angle from the plots was observed around 125 degrees. The minimum time for a slip was found to be 0.4 seconds. The time that the impedance locus stays between the blinders for this case would be 0.8 seconds (0.4 * 2). The relay setting for time between blinders was much lower than this value, and hence considered to be adequate.

c. <u>Superimposing protection setting curves on the R-X diagram:</u>

Rotor angle and R-X plots for Case 2 are shown in figures 7 through 14 for illustration purposes. Similar plots for all selected cases were analyzed. Cases 2.2 show the marginally stable cases (those cases at critical clearing time). Case 2.3 is an unstable case. The distance, loss of field and out of step relay characteristics are shown by superimposing the system impedance locus on the R-X diagram for these two cases. From the rotor angle plots the initial rotor angle is obtained (27 degrees); from the R-X plots the critical angle is 125 degrees. The time from critical angle of 125 degrees (0.57 seconds) to 180 degrees (0.97 seconds) was 0.4 seconds.

It is observed from the plot results for distance protection for cases 2.2 that the impedance locus enters the mho circle for a finite time. However, the time that the impedance locus remains within the mho circle is less than the 1second time delay setting of the distance protection,. For case 2.3 it operates, but based on these observation setting was disabled for power swings. Therefore, the timer setting is considered acceptable for zone 1 and zone 2. The time that the impedance locus remained inside the mho circle is not seen in the graph. This duration is available in the R-X vs. time table that is used to plot the curves, similar to the sample shown in Table 5 in the previous section.

It is observed from the plot results for loss of field protection for cases 2.2 and 2.3 that the impedance locus does NOT enter the mho circle. Hence timer settings are considered as acceptable for these cases. This exercise should be done for the various cases under consideration.

It is observed from the plot results for out of step protection for cases 2.2 and 2.3 that the impedance locus enters the mho circle for case 2.3 (unstable case) and does NOT enter the mho circle for case 2.2 (stable case). Therefore the settings for the out of step relay are considered acceptable; the relay operates for unstable cases and does NOT operate for stable cases. This exercise should also be done for the other cases under consideration.

After superimposing the relay characteristics, the adequacy of all the protection timers should also be checked. The results are summarized as shown in table 7 below. Two other significant verifications of settings were the critical angle and the time duration for a fastest unstable swing remaining within the blinders of out-of-step protection. Results from the stability studies verified the critical angle settings. The fastest swing through the blinders was also detected by the out of step relay with suitable margin (Case 2.3).

Table 7 Protection Superimposition results

Case	Stable/ Unstable	Out Of Step	Loss of Field	Distance
1.1	Stable	No Op	No Op	No Op
1.2	Unstable	Op.	**Opers Note 1**	No Op
2.1	Stable	No Op	No Op	No Op
2.2	Marg. Stable	No Op	No Op	No Op
2.3	Unstable	Op.	No Op	**Opers Note 2**
3.1	Stable	No Op	No Op	No Op
3.2	Marg. Stable	No Op	No Op	No Op
3.3	Unstable	Op.	**Opers Note 1**	No Op
4.1	Stable	No Op	No Op	No Op
4.2	Marg. Stable	No Op	No Op	No Op
4.3	Unstable	Op.	**Opers Note 1**	No Op
5.1	Stable	No Op	No Op	No Op
5.2	Stable	No Op	No Op	No Op
6.1	Stable	No Op	No Op	No Op
6.2	Stable	No Op	No Op	No Op
7.1	Stable	No Op	No Op	No Op

Note 1: Loss of field stage 1 operates for these cases (unstable swings). This is acceptable, though it may initially mislead during troubleshooting.

Note 2: Distance relay operates for this unstable swing. As distance relay is a backup protection, it was disabled during power swings by relay logic.

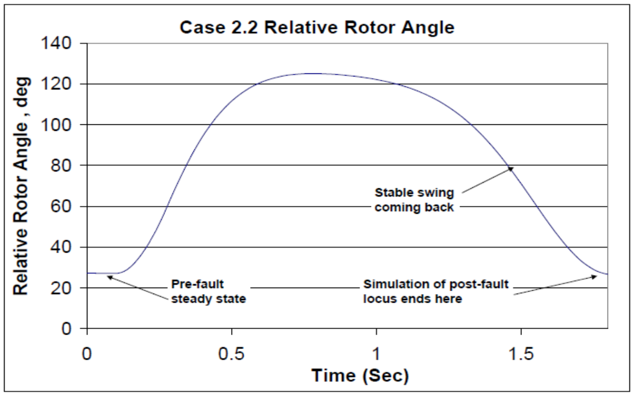

Figure 7: Locus of relative rotor angle during the fault event for Case 2.2

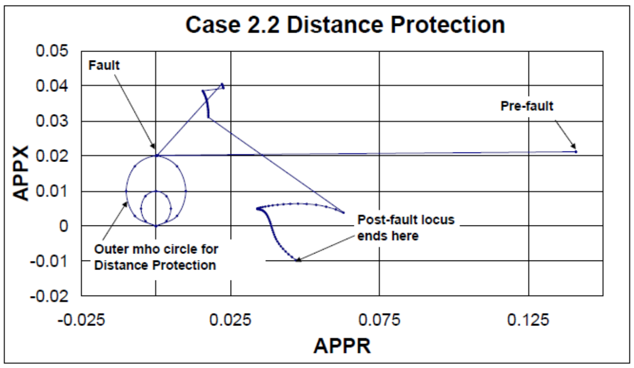

Figure 8: Locus of system impedance seen by the distance protection element for Case 2.2

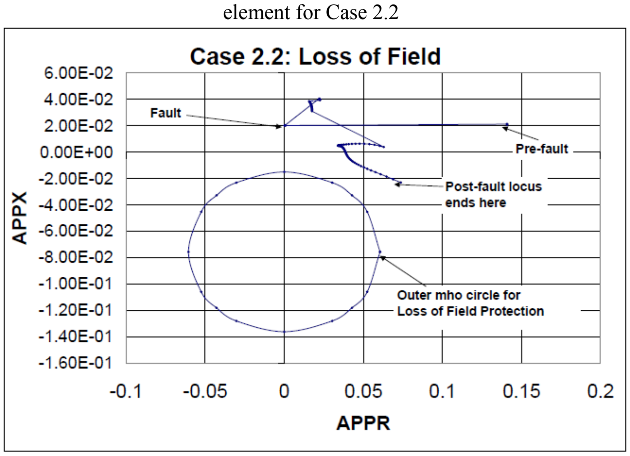

Figure 9: Locus of system impedance in mho plane during the fault event as seen by the loss of field protection for Case 2.2

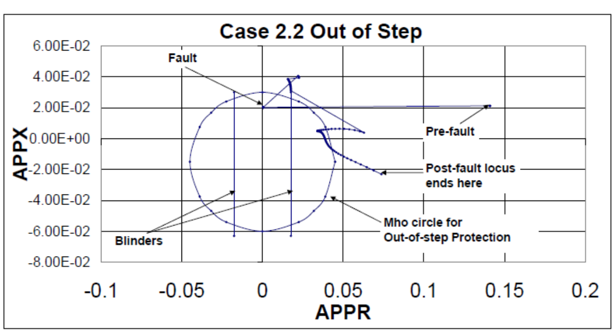

Figure 10: Locus of system impedance in mho plane during the fault event as seen by the out of step protection for Case 2.2

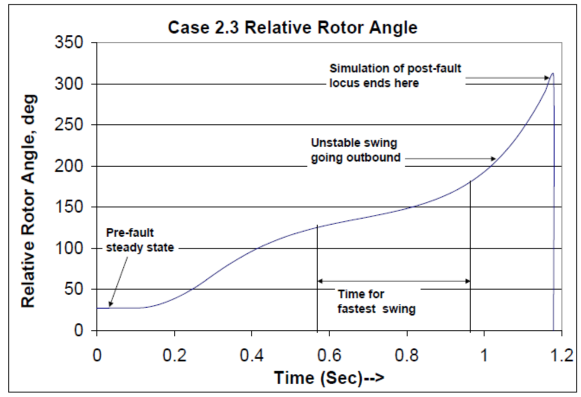

Figure 12: Locus of relative rotor angle during the fault event for Case 2.3

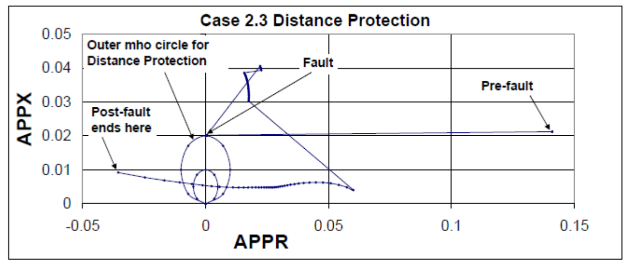

Figure 11: Locus of system impedance seen by the distance protection element for Case 2.3

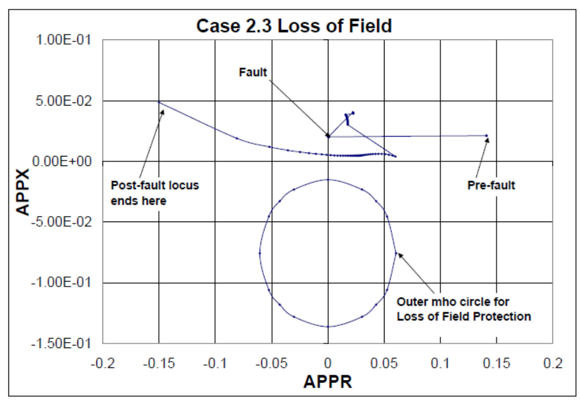

Figure 13: Locus of system impedance in mho plane during the fault event as seen by the loss of field protection for Case 2.3

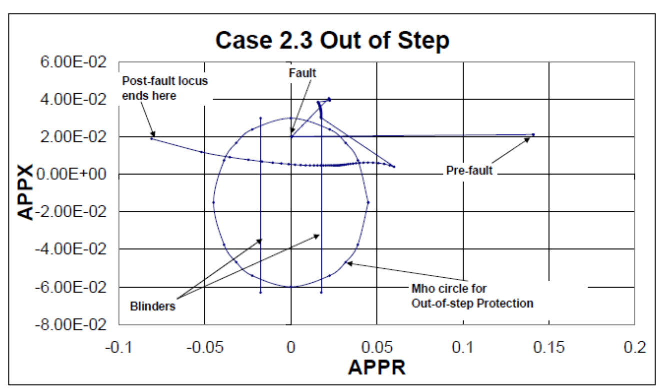

Figure 14: Locus of system impedance in mho plane during the fault event as seen by the out of step protection for Case 2.3

VI. CONCLUSION

This paper outlines relevant concepts for stability studies needed for protection engineers to set system dependent protections for generators. It discusses the relationship between results of stability studies and associated R-X plots. It also describes the superimposition of relay settings for system dependent generator protections on R-X plots obtained from stability studies, and interpretation of the results, thereby enabling the protection engineer to achieve the required level of protection and improved reliability of the generator during power swings in the system.

VII. REFERENCES

[1] P.M Anderson & A.A Faoud,Power System Control and Stability es, ISBN 0-7803-1029-2

[2] Prabha Kundur, Power Stability and Control EPRI Power System Engineering Series, McGraw Hill Inc, 1994

[3] Carson Taylor, Power System Voltage Stability EPRI Power System Engineering Series, McGraw Hill Inc, 1992

[4] Stevenson W.D., *Elements of Power System Analysis*, 3rd ed., 1975, McGraw-Hill, Inc., ISBN 0-07-061285-4.

[5] Working group J6 of Rotating Machine Subcommittee, Power System Relaying Committee., "Performance of Generator Protection during Major System Disturbances ", *IEEE Trans. of Power Delivery*, IEEE paper No TPWRD-00370-2003.

[6] Working group J5 of Rotating Machine Subcommittee, Power System Relaying Committee, "Coordination of Generator Protection with Generator Excitation Control and Generator Capability", *IEEE Power Engineering Soceity*, IEEE paper No 1-4244-1298-6/07.

[7] IEEE C37.102 Guide for AC Generator Protection.

[8] IEEE 421-5 IEEE Recommended Practice for Excitation System Models for Power System Stability studies

VIII. BIOGRAPHIES

Prem Kumar is a Senior Electrical Engineer working for Bechtel Power Corporation. He received his Master's degree in Electrical Engineering from Virginia Tech, VA in 1989. He is a senior member of IEEE. He is actively involved with IEEE PSRC, serving as member of Main Committee, Subcomittee, and several working groups. He is the Chairman of the Guide for AC Motor Protection. His areas of interest are power system analysis, and protection. He is a licensed Professional Engineer in the state of Maryland, US.

Dale Fredrickson is a Senior Electrical Engineer working for We Energies. He received his Bachelor's degree in Electrical Engineering from the University of Wisconsin-Milwaukee in 1978. He is a Member of IEEE. His area of interest is power system protection. He is actively involved with IEEE PSRC, serving as member of Main Committee, Rotating Machinery Subcomittee, and several working groups. He is a licensed Professional Engineer in Wisconsin, US.

Koushik Chanda is a Senior Electrical Engineer working for Bechtel Power Corporation. He received his Bachelor's degree in Electrical Engineering from Jadavpur University, India in 1992. He is a member of IEEE and an active member of several working groups under IEEE Substation Committee. His areas of interest are power systems study and design, protections, and system grounding. He is a licensed Professional Engineer in the District of Columbia, US.