Power Plant Protection and Control Strategies For Blackout Avoidance

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I. INTRODUCTION

Recent misoperations of generation protection during major system disturbances have highlighted the need for better coordination of generator protection with generator capability, generator Automatic Voltage Regulator (AVR) control and transmission system protection. Generator protection misoperations contributed to the 1996 outages in the western U.S. and played a role in the 2003 U.S. East Coast blackout. Since most recent major power system disturbances are the result of voltage collapse, generator protection must be secure during low voltage system conditions while still providing generator protection. In addition, the generator AVR needs to properly control VAr support to rapidly stabilize system voltage during major disturbances. This paper discusses in detail the important role that the generator AVR plays during major system disturbances. As a result of recent blackouts, NERC (North Electric Reliability Council) has mandated tests to verify the coordination of generator protection and control. This paper provides practical guidance on providing this coordination.

II. ROOT CAUSES COMMON TO RECENT BLACKOUTS

Power systems today are much more susceptible to voltage collapses than they were 25 years ago as we increasingly depend on generation sources that are located remotely from load centers. Generators in eastern Canada and the Midwestern U.S. provide large amounts of power to east coast load centers such as New York City. Generators in Washington, Oregon and western Canada provide substantial power to California. Two factors promote generation that is remote from load centers:

1. The economics of purchasing power from lower cost remote sources rather than more expensive local generation.
2. The public does not want new generating plants in urban high load areas, causing utilities/IPPs to build plants that are remote from these load centers.

These two fundamental changes in operation of the U.S. power grid result in the transmission of power over long distances. This makes the power grid very dependent on the transmission system to deliver power to the load centers. It also results in increased reactive power losses.

Reactive power (VArs) cannot be transmitted very far, especially under heavy load conditions, and so it must be generated close to the point of consumption. This is because the difference in voltage causes VArs to flow and voltages on a power system are only typically $^{+}/-$ 5% of nominal which does not cause substantial VArs to flow over long distances. Real power (MW) can be transmitted over long distances through the coordinated operation of the interconnected grid whereas reactive power must be generated at, or near, the load center.

Since VArs cannot be transmitted over long distances, the sudden loss of transmission lines results in an instantaneous need for local reactive power to compensate for the increased losses of transporting the same power over fewer transmission lines. If that reactive support is not available at the load center, the voltage will go down. The impact of reduced voltage on load depends on the nature of the load. For resistive load, the load current will decrease and help limit the need for local reactive support. Motor loads are essentially constant kVA devices. The lower the voltage, the more current they draw—increasing the need for local reactive support. Power systems loads consist of both resistive loads as well as reactive motor loads. During hot weather, however, air conditioning motor loads make up a large portion of total load, thereby making the system more susceptible to voltage collapse.

Power Transfer-Voltage Analysis of Voltage Collapse

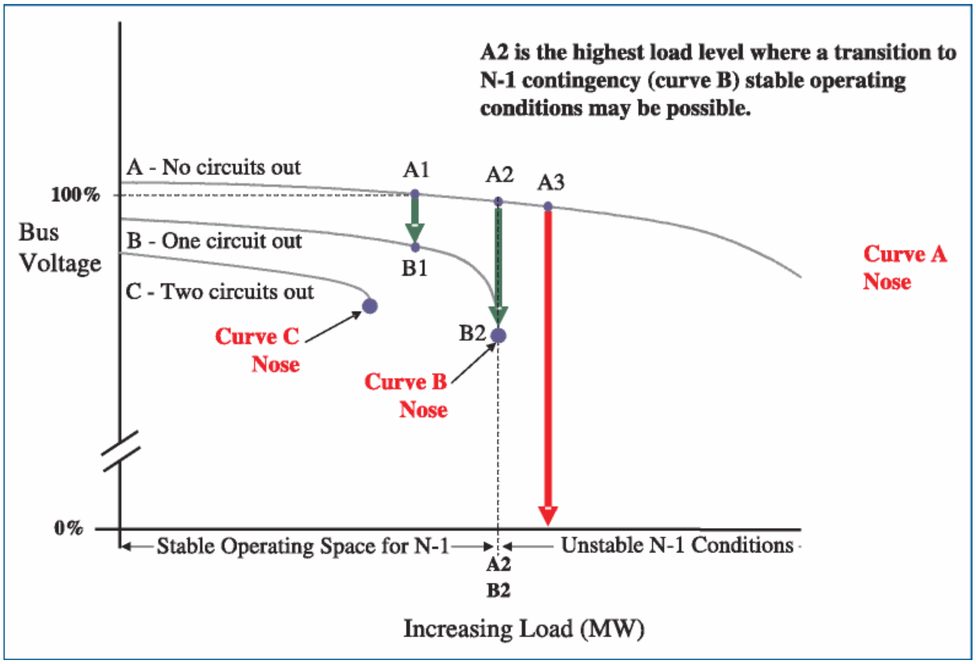


Fig. 1 Real Power vs. Voltage (P-V) Curve

Fig. 1 illustrates how voltage decays as real power at the load center increases. This type of P-V analysis (real power relative to voltage) is an analysis tool, used by system planners, to determine the real power transfer capability across a transmission interface to supply local load. Starting from a state of a base-case system, computer-generated load flow cases with increasing power transfers are run while monitoring voltages at critical buses. When power transfers reach a high enough level, a stable voltage cannot be sustained and the system collapses.

On a P-V curve (see Fig. 1), this point is called the "nose" of the curve. This set of P-V curves illustrates that for baseline conditions shown in curve A, voltage remains relatively steady (changing along the vertical axis) as local load increases. System conditions are secure and stable to the left of point A1. After a contingency occurs, such as a transmission circuit or generator trip, the new condition is represented by curve B, with lower voltages (relative to curve A). The system must be operated to stay well inside the load level for the nose of curve B. If the B contingency occurs, then the next worst contingency must be considered, and the operator and local generator AVR controls must adjust the system voltage to pull back operations to within the safe zone to avoid going over the nose of curve C.

Reactive power system support can only come from two sources: shunt capacitors and generators/synchronous condensers. Shunt capacitors are a double-edged sword. They do provide reactive support, but they also generate fewer VArs as the voltage dips. Shunt capacitor banks cannot quickly adjust the level of reactive power. Modern static VAr compensators do allow rapid reactive power adjustment but these devices are expensive and limited in application.

Generation at the load center can provide a dynamic source of reactive power. As the voltage goes down, the generator can quickly provide increased reactive support within its capability limits. Unlike shunt capacitors, the amount of reactive support does not drop as system voltage goes down. The amount of reactive power is controlled by the generator AVR. It is essential that the AVR control be properly set and the generator protection system allow the generator to contribute the maximum reactive power to support the system while staying within the capability of the generator.

2003 U.S. East Coast Blackout

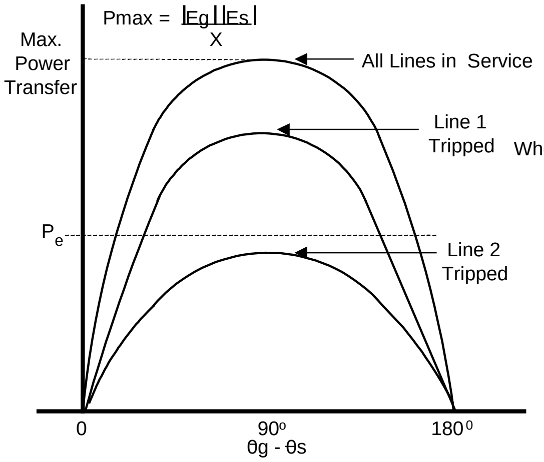
For the reasons cited above, almost all major blackouts occurring in the last ten years involve voltage collapse. The 2003 East Coast blackout was a classic example and demonstrated the importance of keeping generators at the load center in-service during system low-voltage conditions. System voltage for this event decayed over a few hours— giving system operators ample time for corrective action. The loss of SCADA-monitoring prevented them from properly assessing the situation and taking action.

The loss of Eastlake 5—a 597 MW (net) generating unit located east of Cleveland on Lake Erie—was the first major event in the collapse of the system. This unit is a major source of reactive power support for the Cleveland area. The unit tripped 2 hours before the blackout. Analysis by the joint Canadian/U.S. Commission Task Force [1] indicated that had this one generator remained in-service, it would have prevented the blackout. The Eastlake 5 unit tripped when the plant operator removed the generator from automatic AVR control and manually attempted to increase the machine VAr output to raise system voltage. This requires increasing the generator field current. The field current was increased beyond its rating or the AVR excitation limit was exceeded, which resulted in tripping of the field. This resulted in the subsequent proper tripping of the unit by loss-of-field protection. The loss of Eastlake 5, coupled with the tripping of three 345-Kv transmission lines (tree contacts) supporting the Cleveland area, resulted in a cascading event triggered by voltage collapse. This also caused the phase angles between local and remote generations to become large and eventually unstable—resulting in the power grid breaking up into islands.

Major Generator Instability Conditions During Major Disturbances

When the phase angle between local generators and remote generators becomes too large, phase angle instability can occur. In many cases, this event happens in conjunction with the voltage collapse scenario described above. There are three types of generator instability that occur during major disturbances: steady state, transient and dynamic. Each of these instable conditions adversely effects generators and requires protection. The first two are protected by relays at the generator and the third by the generator AVR control.

Steady-State Instability occurs when there are too few transmission lines to transport power from the generating source to the local load center. Loss of transmission lines into the load center results in voltage collapse as described above, but it can also result in steady-state instability. Fig. 2 illustrates how steady-state instability occurs. The ability to transfer real (MW) power is described by the power transfer equation below and is plotted graphically.



POWER TRANSFER EQUATION

$$P_e = \frac{|E_g||E_s|}{X} \sin(\theta_g - \theta_s)$$

Where: Eg = Voltage at the Load Center Generation
Es = Voltage at the Remote Generation
Pe = Electrical Real Power Transfer
X = Reactance Between Local and Remote Generation
θg = Votage Angle and Local Generation
θs = Voltage Angle at Remote Generation

Fig. 2 Power Angle Analysis - Steady-state Instability

From the power transfer equation above, it can be seen that the maximum power (Pmax) that can be transmitted is when $\theta g - \theta s = 90^{\circ}$, i.e. $\sin 90^{\circ} = 1$. When the voltage phase angle between local and remote generation increases beyond 90°, the power that can be transmitted is reduced and the system becomes unstable and usually splits apart into islands. If enough lines are tripped between the load center and remote generation supplying the load center, the reactance (X) between these two sources increases thereby reducing the maximum power (Pmax), which can be transferred. The power angle curve in Fig. 2 illustrates this reduction 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 system goes unstable. During unstable conditions, generators may slip poles and lose synchronism. Out-of-step protection (78 function) is necessary to protect the generator from damage. Voltage collapse and steady-state instability can occur together as transmission lines tripping increases the reactance between the load center and remote generation. A graphical method can be used to determine the steady-state stability limit for a specific generator. This method, as well as protection requirements, is discussed in Sections III and VI of this paper.

Transient Instability occurs when a fault on the transmission system near the generating plant is not cleared rapidly enough to avoid a prolonged unbalance between mechanical and electrical output of the generator. A fault-induced transient instability was not a cause of the 2003 U.S. Northeast blackout. However, generators need to be protected from damage that can result when transmission system protection is slow to operate. Relay engineers design transmission system protection to operate faster than a generator can be driven out of synchronism, but failures of protection systems have occurred that resulted in slow clearing transmission system faults. It is generally accepted [3] that loss-of-synchronism protection at the generator is necessary to avoid machine damage. The larger the generator, the shorter is the time to drive the machine unstable for a system fault.

Fig. 3 illustrates a typical breaker-and-a-half power plant substation with a generator and a short circuit on a transmission line near the substation. If the short circuit is three-phase, very little real power (MW) will flow from the generator to the power system until the fault is cleared. The high fault current experienced during the short circuit is primarily reactive or VAr current. From the power transfer equation, it can be seen that when Eg drops to almost zero, almost no real power can be transferred to the system. The generator AVR senses the reduced generator terminal voltage and increases the field current to attempt to increase the generator voltage during the fault. The AVR control will go into field forcing mode where field current will be briefly increased beyond steady-state field circuit thermal limits. During the short circuit, the mechanical turbine power (P_M) of the generator remains unchanged. The resulting unbalance between mechanical and electrical power (P_e) manifests itself with the generator accelerating, increasing its voltage phase angle with respect to the system phase angle as illustrated in Fig. 3.

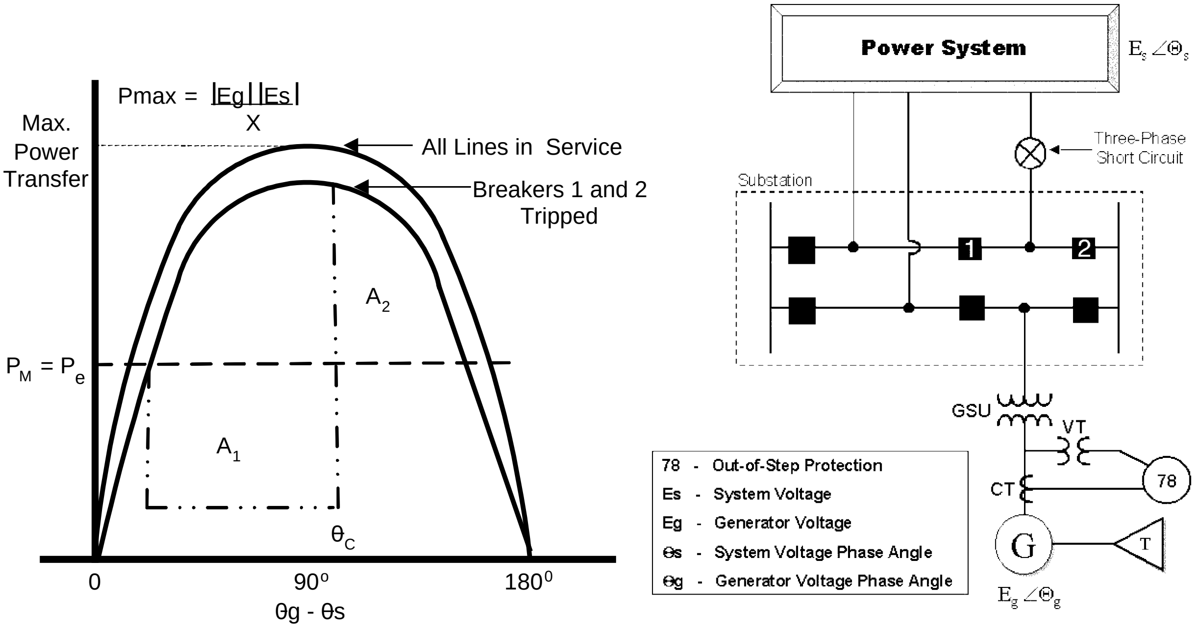


Fig. 3 Power Angle Analysis – Transient Instability

The speed with which the generator accelerates depends on its inertia. The larger the generator, the faster it will accelerate. If the transmission system fault is not cleared quickly enough, the generator phase angle will advance so that it will be driven out of synchronism with the power system. Computer transient stability studies can be used to establish this critical switching angle and time. The equal area criteria can also be applied to estimate the critical switching angle (θ_c). When area $A_1 = A_2$ in Fig. 3, the generator is just at the point of losing synchronism with the power system. Note that after opening breakers 1 and 2 to clear the fault, the resulting power transfer is reduced because of the increase in reactance (X) between the generator and the power system. This is due to the loss of the faulted transmission line. In the absence of detailed studies, many users establish the maximum instability angle at 120°. Because of the dynamic nature of the generator to recover during fault conditions, the 120° angle is larger than the 90° instability point for steady-state instability conditions. The time that the fault can be left on the system that corresponds to the critical switching angle is called the “critical switching time.” If the fault is left on longer than that time, the generator will lose synchronism by “slipping a pole.” For this condition, the generator must be tripped to avoid shaft torque damage. Relay function 78, discussed in Section VI of this paper, describes such protection.

Dynamic Instability occurs when a fast-acting AVR control amplifies rather than damps some small low frequency oscillations that can occur in a power system. This problem has been most often associated with the western region of the U.S. It can, however, occur anywhere the load is remote from the generation. While fast excitation systems are important to improve transient stability as discussed above, a fast-responding excitation system can also contribute a significant amount of negative damping. This reduces the natural damping torque of the system, causing undamped megawatt oscillations after a disturbance such as a system fault. It can occur if the generator is interconnected to a weak system and loads are far from the generating plant. As discussed above, the operation of today's power grid makes this scenario much more likely in many regions of the U.S.

Small signal stability is defined as the ability of the power system to remain stable in the presence of small disturbances most often caused by remote faults. If sufficient damping torque does not exist, the result can be generator rotor angle oscillations of increasing amplitude. When these megawatt oscillations grow, the generator can eventually be driven unstable, lose synchronism and slip a pole. To address this problem, a Power System Stabilizer (PSS) is utilized in conjunction with the generator AVR to provide positive damping when megawatt oscillations occur. Section VII of the paper discusses PSS in more detail.

III. GENERATOR/CONTROL CAPABILITY AND SYSTEM CALCULATIONS

The role that the AVR plays in maintaining generator operation within generator capability limits is an important concept for protection engineers to understand. During system stress conditions, these limits are frequently challenged when system conditions such as voltage collapse or steady-state stability limits might be reached. A graphical method, discussed in this section of the paper, can be used to determine the steady-state stability limit and provide an important tool to ensure coordination with generator protection and AVR control.

Excitation AVR Control Basics

The excitation system of a generator provides the energy for the magnetic field that keeps the generator in synchronism with the power system. In addition to maintaining the synchronism of the generator, the excitation system also affects the amount of reactive power that the generator may absorb or produce. If the terminal voltage is fixed, increasing the excitation (field) current will increase the reactive power output. Decreasing the excitation will have the opposite effect, and in extreme cases, may result in loss of synchronism of the generator with the power system. If the generator is operating isolated from the power system, and there are no other reactive power sources controlling terminal voltage, increasing the level of excitation current will increase the generator terminal voltage and vice versa.

The most commonly used voltage control mode for generators of significant size that are connected to a power system is the AVR (Automatic Voltage Regulator) 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 short circuits depress the system voltage, electrical power cannot fully be delivered to the transmission system. Fast response of the AVR and excitation system help to increase the synchronizing torque to allow the generator to remain in synchronism with the system. The over excitation limiter (OEL) must limit excitation current before the generator field overload protection operates. The under excitation limiter (UEL) prevents the AVR from reducing excitation to such a low level that the generator is in danger of losing synchronism. Section VII of this paper has a more detailed discussion of AVR control response during major system disturbances.

Generator Capability

A typical generator capability curve is shown in Fig. 4. The capability curve establishes the generator operating limits. The curve also shows how the AVR control limits operation to within generator capabilities.

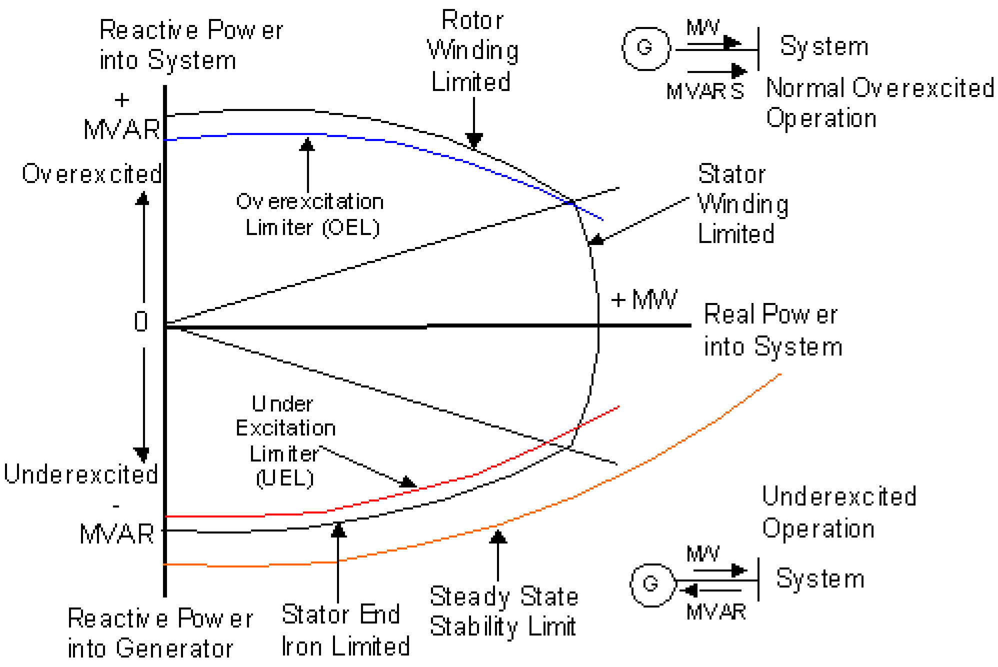


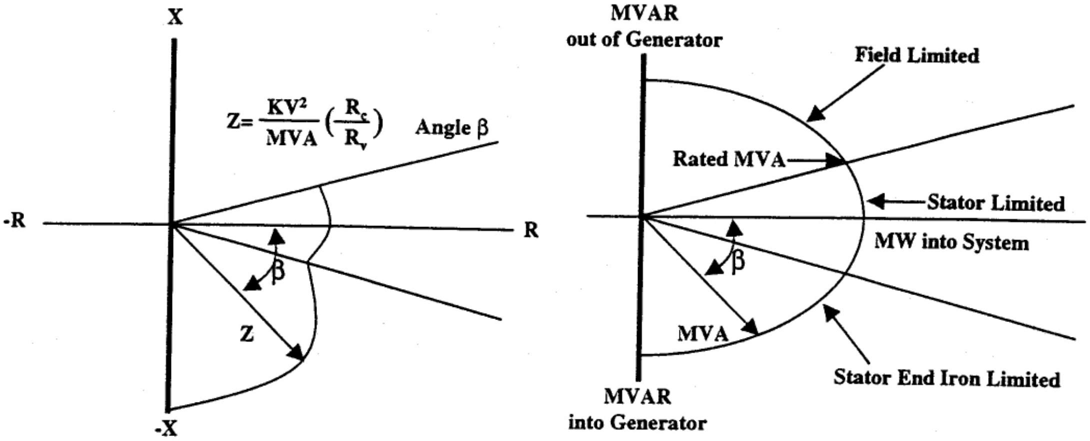
Fig 4 Typical Generator Capability Curve and Operating Limits

The generator capability is a composite of three different curves: the stator winding limit, the rotor heating limit and the stator end iron limit. The stator winding limit is a long-term condition relative to the generator winding current carrying capability. The rotor heating limit is relative to the rotor's current carrying capability. It is also associated with longer time conditions. The stator end iron limit is a relatively short time condition, caused by a reduction in the field current to the point where a significant portion of the excitation is being supplied from the system to the generator. Significant underexcitation of the generator causes the rotor retaining ring to become saturated. The eddy currents produced by the flux cause localized heating. Hydrogen-cooled generators have multiple capability curves to reflect the effect of operating at different H_2 pressures.

The generator AVR control limiters restrict operation of the generator to within its capabilities and must be set to coordinate with the capability curve as shown in Fig. 4. The setting of the AVR UEL control is coordinated with the steady-state stability limit of the generator which is a function of the generator impedance, system impedance and generator terminal voltage. The generator minimum excitation limiter prevents the exciter from reducing the field below the steady-state stability limit. Section II of this paper discusses steady-state stator stability in general terms and the next sections of this paper will outline a graphical method for determining the steady-state stability limit for a specific generator. The overexcitation control (OEL) limits generator operating in the overexcited region to within the generator capabilities curve. Some users set the OEL just under the machine capability curve as shown in Fig.4, while others set it just above the capability curve.

P-Q to R-X Conversion

Both Figures 4 and 5b illustrate the capability of a generator on a MW-MVAr (P-Q) diagram. This information is commonly available from all generator manufacturers. Protection functions for the generator, such as loss-of-field (40) and system backup distance (21) relaying measure impedance, thus these relay characteristics are typically displayed on a Resistance-Reactance (R-X) diagram. To properly coordinate the generator capability with these impedance relays, it is necessary to convert the capability curve and excitation limiters (UEL and OEL) to an R-X plot. Figure 5 illustrates this conversion. The CT and VT ratios (Rc/Rv) convert primary ohms to secondary quantities that are set within the relay and KV is the rated voltage of the generator.



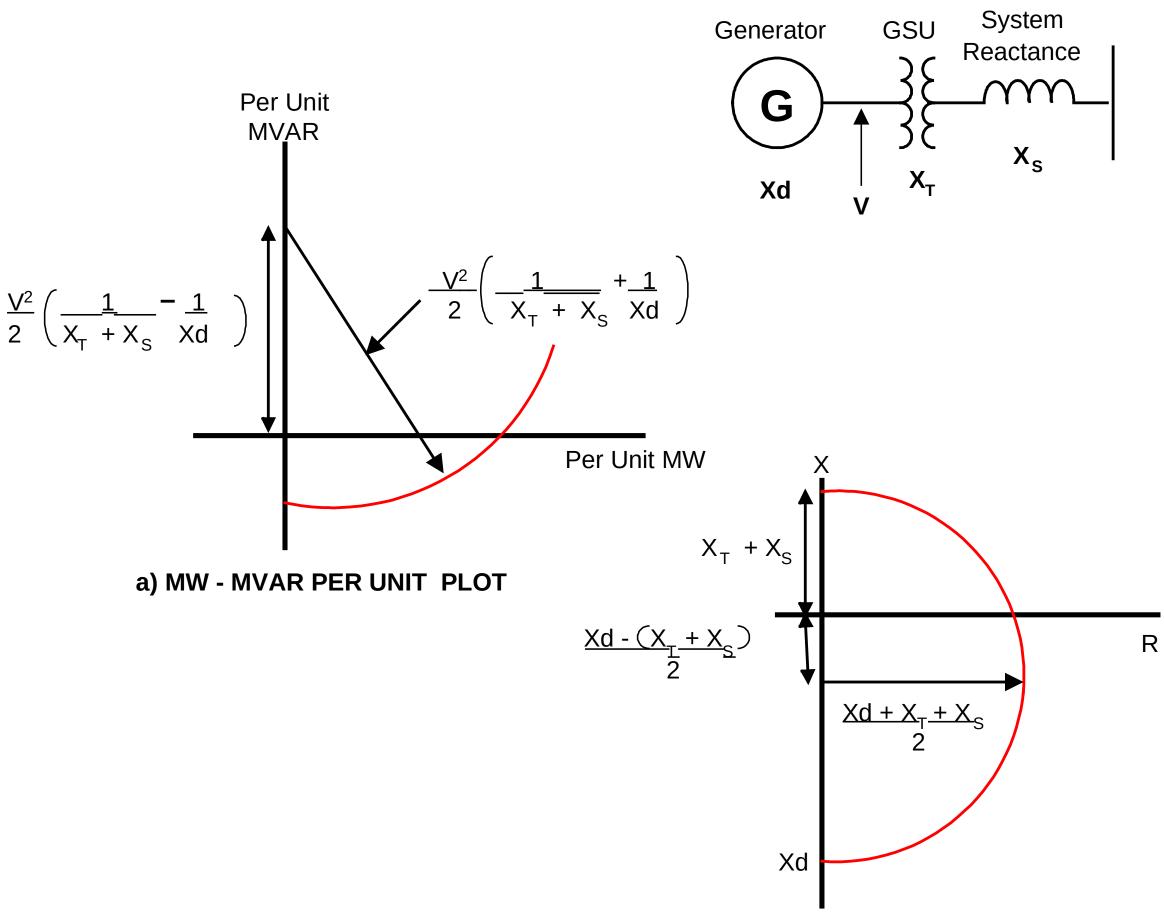
a) R-X Plot b) MW-MVAr Generator Capability Curve

Fig. 5 Transformation for Mw-MVAr to R-X Plot

Steady-State Stability Limit

The steady-state stability limit (see Section II) reflects the ability of the generator to adjust for gradual load changes. The steady-state stability limit is a function of the generator voltage and the impedances of the generator, step-up transformer and power system to which the generator is connected. A graphical method of determining steady-state stability is widely used within the industry to ensure that protective relay such as the loss-of-field (40) protection and AVR under excitation limiter (UEL) are properly coordinated. The graphical method illustrated below displays the steady-state stability limit on both an MW-MVAr and R-X diagram.

In Fig. 6a, V is the per-unit terminal generator voltage, and X_T and Xs are the per-unit generator step-up (GSU) transformer and system impedances, respectively, as viewed from the generator terminals. X_d is the per-unit unsaturated synchronous reactance of the generator. All reactances should be placed on the generator MVA and voltage base.



a) MW - MVAR PER UNIT PLOT

b) R-X DIAGRAM PLOT

Fig. 6 Graphical Method for Steady-state Stability Analysis

The generator cannot be operated beyond the steady-state stability limit. It should be noted that the weaker the transmission system, the smaller the circle radius. Often, the system reactance model will consist of the normal system without the single strongest line to address the worst-case line out-of-service condition. This increases the system reactance—providing a more conservative value of X_S. In most cases, the steady-state stability limit is outside the generator capability curve, and does not restrict generator operation.

IV. <u>COORDINATION OF GENERATOR PROTECTION WITH AVR CONTOL</u>

It is important that the generator AVR control and generator protection is coordinated and that the generator protective relay system be secure for the lowest credible voltage for which utility planning people expect the system to survive. AVR control and generator protection should allow generators to provide the maximum reactive power support to the system. Once the system voltage collapse occurs, the system typically breaks up into islands. There are islands where there is an excess of reactive power versus reactive load resulting in high voltage. Generators—being a dynamic VAr source—can operate underexcited to absorb system VArs to reduce voltage. It is important to check the underexcited capability of the generator AVR control as well as protection to ensure that the generator can operate in this mode without tripping.

Coordination of AVR Control with Loss-of-Field (40) Protection

To limit system voltage during islanding conditions, generators may have to operate underexcited and absorb VArs from the power system. It is important that the generator be able to do so within its capabilities as defined by the generator capability curve. The generator AVR under excitation limiter (UEL) must be set to maintain operation within the capability curve as show in Fig. 4. The loss-of-field relay should also be set to allow the generator to operate within its underexcited capability. The generator AVR uses the generator terminal voltage and phase current to calculate generator operating conditions. By comparing the actual point of operation to the desired limit, the AVR determines when it is appropriate to adjust the generator field current to maintain the desired generator operating voltage.

Partial or total loss-of-field on a synchronous generator is detrimental to both the generator and the power system to which it is connected. The condition must be quickly detected and the generator isolated from the system to avoid generator damage. A loss-of-field condition, which is not detected, can have a devastating impact on the power system by causing both a loss of reactive power support, as well as creating a substantial reactive power drain. This reactive drain, when the field is lost on a large generator, can cause a substantial system voltage dip. When the generator loses its field, it operates as an induction generator causing the rotor temperature to rapidly increase due to the slip-induced eddy currents in the rotor. The high reactive current drawn by the generator from the power system can overload the stator windings.

The most widely applied method for detecting a generator loss-of-field condition is the use of distance relays to sense the variation of impedance as viewed form the generator terminals. A two-zone distance relay approach is widely used within the industry to provide high-speed detection. Fig. 7 illustrates this approach. An impedance circle diameter equal to the generator synchronous reactance (Xd) and offset downward by ½ of the generator transient reactance (Xd') is used for the zone 2 distance element. The operation of this element is delayed approximately 30-45 cycles to prevent misoperation during a stable transient power swing. A second relay zone (zone 1) is set at an impedance diameter of 1.0 per unit (on the generator base), with the same offset of ½ of the generator transient reactance. This zone has a slight time delay of 2 to 5 cycles and is used for high-speed detection of more severe loss-of-field conditions. The loss-of-field setting, determined as described above, must be checked for coordination with the generator capability curve, AVR under excitation limiter setting and steady-state stability limit using the calculation method described in Section III of this paper. Fig. 7 illustrates this coordination on a R-X diagram.

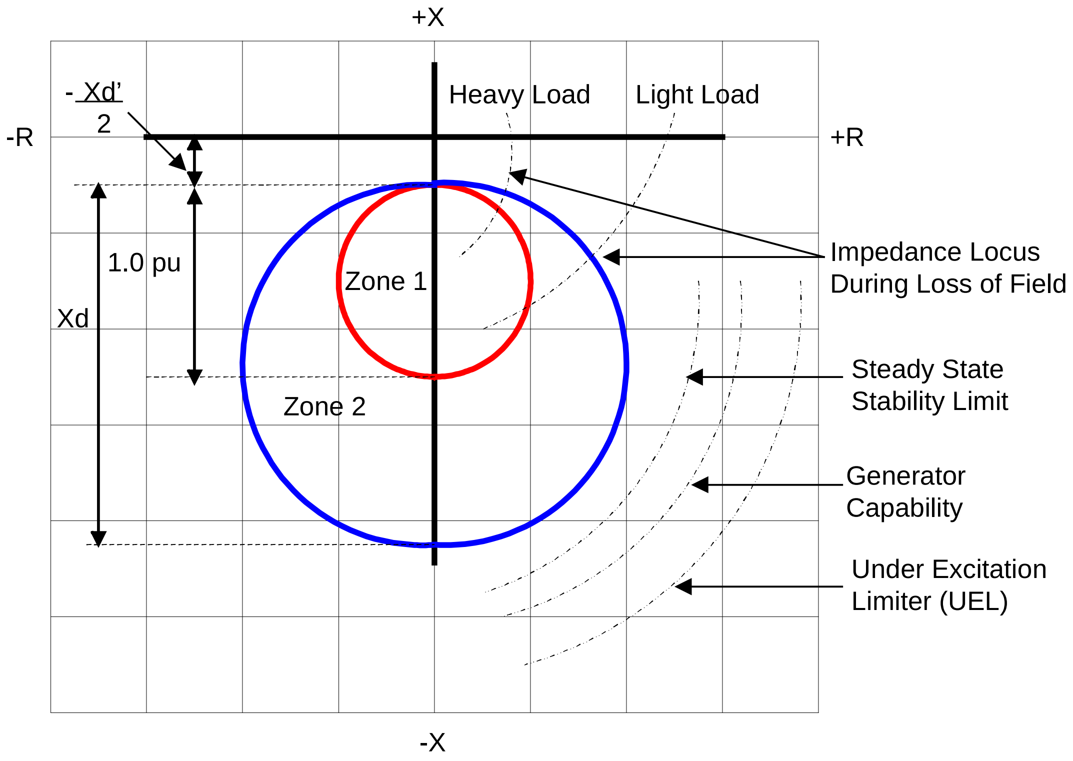


Fig. 7 Modern Loss-of-Field Protection Using a Two-Zone Off-Set Mho Method

Coordination of AVR Control with Overexcitation V/Hz (24) Protection

The flux in the stator core of a generator or core of a transformer is directly proportional to voltage and inversely proportional to frequency. Overexcitation of a generator or any transformer connected to the generator terminals will occur whenever the ratio of voltage to frequency (V/Hz) applied to the terminals exceeds 1.05 pu (generator base) for a generator, and 1.05 pu (transformer base) for a transformer at full load. The transformer no-load level is 1.10 pu. For transformers, the point of measurement is the output terminals. IEEE/ANSI C50.12 and C50.13 [2] provide minimum standards for generators. The manufacturer should be consulted for V/Hz capability of a specific generator. When these V/Hz ratios are exceeded, saturation of the iron core of generators and transformers will occur—resulting in excessive eddy current heating and voltage breakdown of inter-lamination insulation.

During system disturbances, overexcitation is caused by the sudden loss of load due to transmission line tripping, which can island the generator from the power grid with little load, and the shunt capacitance of the unloaded transmission lines. Under these conditions, the V/Hz level may exceed 1.25 pu. With the AVR control in service, the overexcitation will generally be reduced to safe limits in a few seconds by the reduction of generator field current. The AVR OEL limiter will limit the V/Hz generator output to a set maximum within the generator capability curve. Even with a V/Hz limiter in the excitation control, it is common and recommended practice [3] to provide separate V/Hz relaying to protect the generator and any transformers connected to the generator terminals. In modern applications where digital relays are used, the V/Hz protection of the transformer resides in the transformer protection relay and is set to protect the transformer. Both generator and transformer protection must be coordinated with the AVR control. The exciter's V/Hz limiting should be set at the upper limit of the normal operating range and below the continuous operating limit for the generator and unit-connected transformer. Similarly, a V/Hz relay(s) should be set with enough delay to allow AVR control action to take place before tripping the unit. This relay, however, must still protect the generator from damage.

There are two basic types of V/Hz protection schemes used within the industry. The first and most common is the dual definite time setpoint method. Typical conservative protection applications recommend a maximum trip level at 1.18 pu V/Hz with a 2-6 second time delay for the first setpoint. The second setpoint is set at 1.10 pu V/Hz with a time delay of 45-60 seconds.

The second method uses an inverse-time characteristic curve as well as definite time setpoints to better match the inverse time V/Hz capability of the generator. This scheme can be precisely applied when a V/Hz versus time curve for a specific generator is available. The minimum pickup is typically 1.10 pu V/Hz. The inverse-time function is set with a greater time delay than the exciter to permit the exciter to operate to reduce the voltage before protection action takes place.

V. GENERATOR PR0TECTION TACTICS TO PROVIDE SECURITY AGAINST STABLE SWINGS AND LOAD ENCROACHMENT

It is the widespread and recommended practice [3] to provide direct tripping backup protection that trip the generators if a transmission system fault is not cleared in a timely manner. This protection is delayed to coordinate with transmission system backup protection and breaker failure. The primary purpose of generator backup protection is to protect the generator from supplying prolonged fault current to faults on the power system. These relays, however, have frequently operated improperly during major system disturbances—unnecessarily tripping generators and thereby exacerbating the disturbance. This was the case during the 1996 West Coast blackout. Investigation revealed that these relays were improperly set for the system conditions they encountered and were expected to “ride through.” They operated due to stable power swings or load encroachment during low system voltage conditions. This section of the paper addresses improving security for these relays.

Two types of relays are commonly used for system phase fault backup: a distance relay and a voltage-restrained or voltage-controlled time overcurrent relay. The choice of relay type is usually a function of the type of relaying used on the lines connecting the generator to the system. To simplify coordination, distance relays are installed where distance relaying is used for line protection, while the overcurrent type of backup relaying is used where overcurrent relaying provides line protection. Generally, larger generators use distance backup protection while smaller generators employ voltage overcurrent backup.

Generator Phase Distance (21) Backup Protection

A mho distance relay characteristic is commonly used to detect system phase faults and to trip the generator after a set time delay. The relay’s impedance reach and delay settings must be coordinated with transmission backup protection and breaker failure to allow selectivity. Typically, the phase distance relay’s reach begins at the generator terminals and ideally extends to the length of the longest line out of the power plant transmission substation. Some factors impacting the settings are as follows:

1. *In-feeds*: Apparent impedance due to multiple in-feeds will require larger reaches to cover long lines and will overreach adjacent shorter lines. The apparent impedance effect occurs because the generator is only one of several sources of fault current for a line fault. This causes the ohmic value of the faulted line to appear further away and requires a larger ohmic setting to cover faults at the remote end of the line.

2. *Transmission System Protection*: If the transmission lines exiting the power plant have proper primary and backup protection, as well as local breaker failure, the need to set the 21 generator relay to respond to faults at the end of the longest lines is mitigated since local backup has been provided on the transmission system.

3. *Load Impedance*: Settings should be checked to ensure the maximum load impedance ($Z_{Load} = kV^2 / MVA_G$) at the generator’s rated power factor angle (RPFA) does not encroach into the 21 relay setting. A typical margin of 150-200% is recommended [4] to avoid tripping during power swing conditions. Due to recent blackouts caused by voltage collapse, the 21 distance setting should be checked for proper operating margins when the generator is subjected to low system voltage. Note that the impedance is reduced by the square of the voltage. System voltage under emergency conditions can reduce to planned levels of 90 to 94 percent of nominal ratings. Utility transmission planners should be

consulted for worst-case emergency voltage levels. In almost all cases, the loadability considerations limit the reach of the generator 21 backup relay setting.

Distance relays with a mho characteristic and one or two zones are commonly used for phase fault backup. If only one zone is used, its setting is based on the zone 2 criteria outlined below. Setting generator backup protection with adequate margin over load and stable power swings is an art as well as a science. The suggested criteria below provide reasonable settings that can be verified for security using transient stability computer studies.

The zone 1 relay element is set to the smaller of two conditions:

1. 120% of the unit transformer impedance.
2. Faults 80% of the zone 1 relay setting of the shortest transmission line exiting the power plant (neglecting in-feeds).

A time delay of approximately 0.5 seconds gives the primary protection (generator differential, transformer differential and overall differential) enough time to operate before the generator backup function.

The zone 2 relay element is typically set at the smallest of the following three criteria:

1. 120% of the longest line with in-feeds.
2. 50 to 67% of the generator load impedance (Z_{load}) at the rated power factor angle (RPFA) of the generator. This provides a 150 to 200% margin over generator full load. This is typically the prevailing criteria.
3. 80 to 90% of generator load impedance at the maximum torque angle of the zone 2 impedance relay setting (typically 85°).

The capability curve for the generator and settings are plotted on the R-X diagram as shown in Fig. 8. The time delay for the zone 2 relay should be set longer than the transmission lines backup and breaker failure protection with appropriate margin for proper coordination.

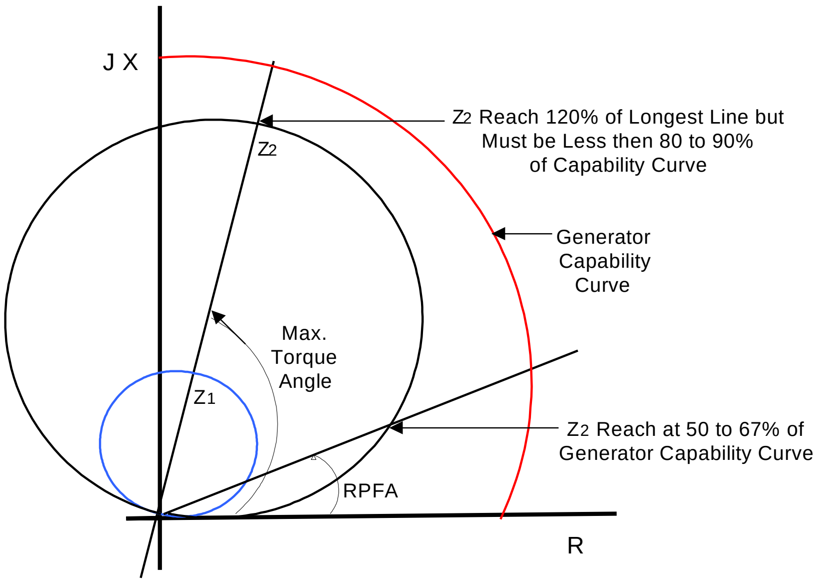


Fig. 8 Generator Phase Distance Backup Protection Settings

To enhance security and safe load margins while still providing the necessary zone 2 relay reach, it is possible to use both load encroachment and out-of-step blocking techniques. Out-of-step blocking uses a zone 3 impedance element that completely surrounds the zone 2 trip element to provide blocking logic. The zone 3 distance element must be set less than the capability of the generator as illustrated in Fig. 9. For power system swing conditions, the impedance locus will first enter into zone 3 before entering zone 2. For fault conditions, the impedance will instantaneously enter the zone 2 trip characteristic. Out-of-step logic is provided such that if zone 3 operates prior to zone 2, a power swing condition exists and zone 2 is blocked from operating. To enhance steady-state loadability, a notch blinder is used as illustrated in Fig. 9. The part of the zone 2 trip circle is blocked from operating to increase loadability at the generator's rated power factor angle (RPFA). Both these techniques are available in multifunction digital generator relay packages.

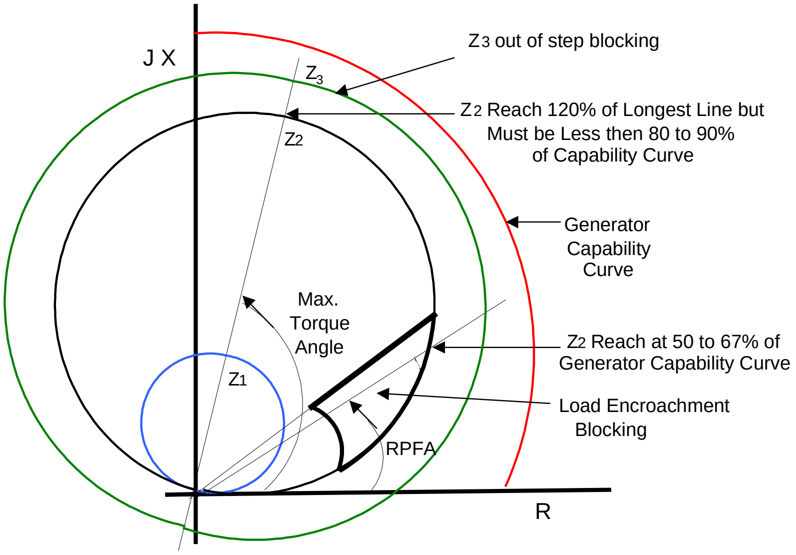


Fig. 9 Security Enhancements for Generator Phase Backup Distance Protection

Generator Voltage Overcurrent (51V) Backup Protection

Two types of voltage overcurrent relays are widely used to provide generator phase fault backup protections. As with distance backup protection, these relays are installed at the generator and provide direct tripping for slow clearing system faults. Tripping must be delayed to coordinate with system backup and breaker failure protection. For generators connected to weak systems, the voltage drop at the generator for remote system fault may not be substantially different than emergency voltage conditions. For these cases, settings should be based on providing the necessary security. System backup shortcoming can be addressed by improving the protection on the transmission system through the installation for delineated primary and backup line protection, as well as local breaker failure. Use of distance relay schemes described above can also provide added flexibility in addressing the problem.

Voltage-Controlled Overcurrent Relays are designed to operate a time overcurrent element when the voltage element within the relay senses a voltage that is below a level set by the user. Under both normal and emergency operating conditions, the voltage relay should be set so as not to enable the overcurrent element. For fault backup conditions, the voltage dip is much greater and the voltage relay is set to operate, allowing the overcurrent relay to trip. Because of the delay involved in tripping, the pickup value of the overcurrent relay is set based on fault current levels determined by the generator synchronous reactance (Xd). This typically requires pickup settings of 30-40% of generator full load current. Setting the voltage element well below the worst case voltage for which the system is expected to survive provides the security against false operating during system disturbances. The worst-case system voltage level could be as low as 90% of normal. The overcurrent element is delayed to coordinate with system backup relaying. A number of voltage-controlled overcurrent relays falsely operated during the 1996 West Coast blackout because the voltage element was improperly set above emergency system voltage experienced during the event.

Voltage-Restrained Overcurrent Relays are designed such that when voltage is reduced, the overcurrent element pickup is automatically proportionally reduced. This occurs over a range of voltages from 25 to 100% of normal. For voltages below 25%, the overcurrent pickup is maintained at the 25% level. The pickup of the overcurrent element should be set at 150% of the generator-rated current. This provides a margin of 135% should the system voltage be reduced during emergency conditions to 90% of normal. The overcurrent element must be delayed to coordinate with system backup relaying and is set based on fault current levels determined by the generator synchronous reactance (Xd).

VI. GENERATOR PROTECTION TACTICS TO PROVIDE RELIABILITY FOR TRIPPING ON UNSTABLE POWER SWINGS AND UNDERVOLTAGE

As discussed in detail in Section II of this paper, power system conditions such as steady-state and transient instability can cause a generator to be driven unstable, lose synchronism with the system and slip a pole. When this occurs, the generator should be tripped as soon as possible to prevent generator damage and before more widespread system outages develop. Out-of-step conditions when the generator has slipped a pole cause high currents in the generator windings and high levels of transient shaft torque. If the slip frequency of the unit with respect to the power system approaches a natural torsional frequency of the shaft, the torques can be high enough to break a shaft. The unit step-up transformer will also be subjected to very high transient winding currents that impose high mechanical stresses on its windings.

Out-of-Step (78) Generator Protection

Following the 1965 U.S. Northeastern power blackout, considerable attention was given to the need for applying out-of-step protection to generators. Prior to EHV transmission systems and large generators, the electrical center during an out-of-step occurrence was out in the transmission system. Thus, the impedance locus could be detected by transmission line out-of-step relaying schemes, and the system could be separated without the need for tripping generators. With the advent of modern EHV systems, system impedances have decreased. As a result, in most power systems today, the electrical center for out-of-step conditions occur in the generator or in the step-up transformer for a fault near the generator.

Fig. 3 in Section II of this paper provides a detailed description of transient stability from a power angle analysis point of view. The best way to detect an out-of-step generator condition, however, is to analyze the apparent impedance variations with time as viewed at the terminals of the generator. This variation in impedance can be detected by distance-type relays. The apparent impedance locus depends on the type of excitation system on the unit as well as the type of fault that initiated the impedance swing.

Fig. 10 illustrates this concept on an R-X diagram as viewed from the terminals of the generator. This is the normal location for the out-of-step (78) relay as shown in Fig. 3. The generator transient reactance (X'_d), GSU transformer reactance (X_T), and power system reactance (X_S) are plotted on an R-X diagram. These impedances should be put on the generator MVA and voltage base. If one assumes $|E_s| = |E_g|$, the locus of the system swing will be located on a perpendicular line bisecting the line drawn between X_S and X'_d as shown in Fig. 10. In this widely used graphical out-of-step method, the reactance elements in the out-of-step relay are set at $\theta_C = 120^\circ$.

More precise angle settings can be determined from stability studies or through equal area criteria analysis as discussed in Section II of this paper. When the swing locus exits blinder A or the supervising Mho circle, generator tripping is initiated. When this happens, the generator has lost synchronism; it has slipped a pole and must be separated from the system.

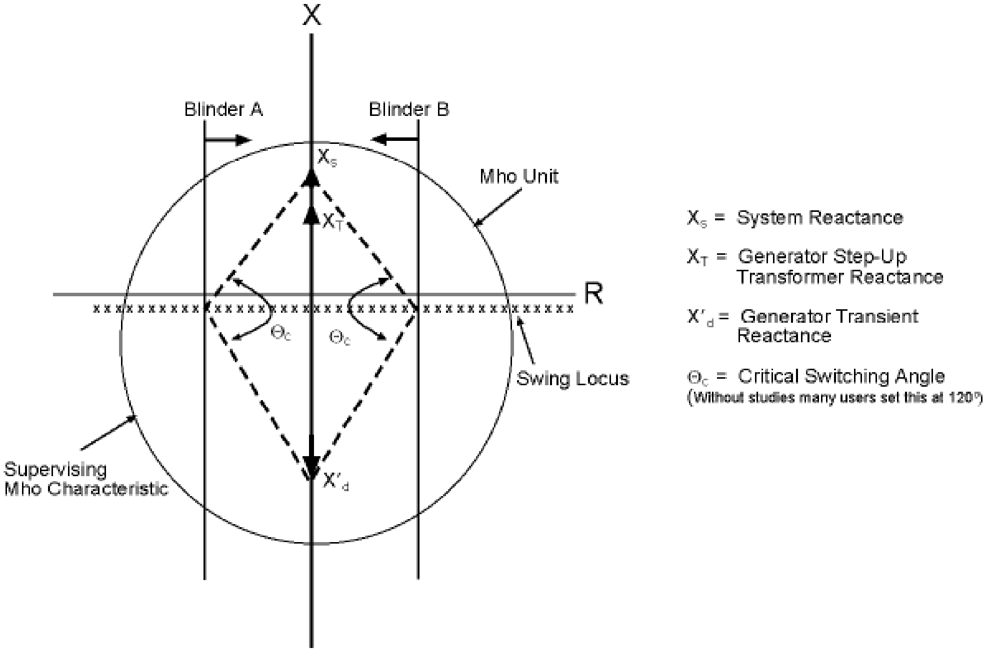


Fig. 10 Impedance Locus Analysis of Out of Step Protection

Undervoltage Tripping Brought About by System VAr Deficits

Undervoltage conditions are not harmful to synchronous generators and there is no recommendation within IEEE protection guides (such as C37.102) [3] that recommend tripping of the machines for low-voltage conditions. This statement is true only if the excitation system AVR control operates properly. An indirect effect of low system voltage that has tripped generators during system disturbances is the loss of auxiliary motors, which overheat due to extended operation at low voltages. Local motor protection trips these motors. With the loss of key auxiliary motors, steam and gas turbines typical trip—resulting in the loss of these generators.

Auxiliary system undervoltage tripping is applied at all U.S. nuclear plants where protection of safety-related auxiliary equipment is of paramount importance. These undervoltage relays are located on the auxiliary system bus and are typically set close to 90% of normal operating voltage, with time delays to prevent tripping for system fault conditions. These schemes are designed to separate the nuclear auxiliary system from the power system at these voltage levels because the system voltage has decayed to a point where the nuclear plant cannot safely shut down because of the worst-case scenario of a loss-of-coolant accident. System relay engineers and system planners should recognize the loss of nuclear generation at low voltage levels when modeling disturbances.

During some system disturbances where interconnected regions become separated, scheduled interchanges can no longer be maintained during the immediate post-disturbance timeframe. If Automatic Generation Control (AGC) is in service, it may try to adjust generator outputs in a fruitless attempt to maintain scheduled interconnection transactions though transmission paths that no longer exist. Such blind AGC control can result in unacceptable voltage and frequency. Special protection schemes applied for system protection may include control action to suspend AGC under these conditions.

VII. RESPONSE OF AVR CONTROL AND LIMITERS DURING MAJOR DISTURBANCES

In North America, the North America Electric Reliability Council (NERC) requires that system operators have positive assurances that generator excitation controls are in service and that specified generator reactive power is available. Assurance of this capability requires periodic testing of the AVR control to ensure it is operating properly and it coordinates with the protection system. NERC is also requiring specific data for generators that are interconnected to the power grid and above a specific MVA size (in some cases, as small as 10 MVA). This information includes:

- Reactive capability range of the generator
- Excitation system models with data validated by tests
- Generator characteristics and synchronous, transient and subtransient reactances that are verified by test data
- Excitation limiters must be modeled and verified

- Generator protection relays must be verified that they coordinate with excitation limiters. (The methods for doing this coordination are described in this paper.)
- The excitation system must be operated in the automatic mode.
- For generators operating in the western United States, a power system (PPS) must be enabled and a verified model provided.

These NERC requirements [6] point out the importance of the generators AVR control and associated excitation systems in helping avoid system blackouts. During system stress conditions, the AVR limits are frequently challenged when system conditions such as voltage collapse or steady-state stability limits might be approached. The AVR control limiters play an important role in making sure the generator is operated within its capability while providing short-time positive and negative field forcing to help stabilize both high- and low-transient system voltage due to fault and load rejections.

Effects of Voltage Depression on AVR Control and Limiters

The generator AVR uses the generator terminal voltage and phase current to calculate generator operating conditions as shown in Fig. 11. By comparing the actual point of operation to the desired level, the AVR determines when it is appropriate to adjust the generator field current to maintain the desired generator operating voltage. Depending on the specific manufacturer, the AVR limiter settings may change with voltage. Some AVR limiters change as the square of the voltage (90% voltage results in 81% of the setting), while others are proportional with the voltage (90% voltage results in 90% of the setting). Still other limiters may not change with voltage at all. To assure proper operation for all conditions, the specific limiter voltage variation characteristic should be identified when setting the limiter and the performance at the lowest credible operating voltage examined.

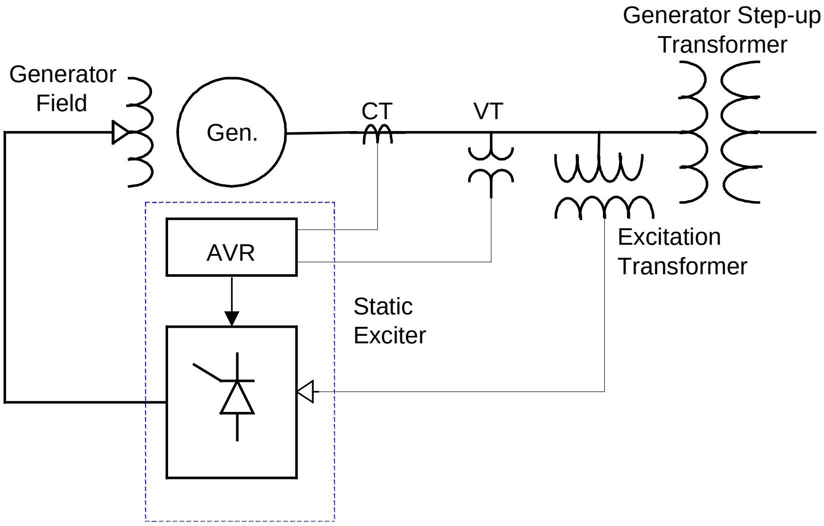


Fig. 11 Basic Static Excitation System

AVR Limiters and Response During Disturbances

In disturbances where short circuits depress the system voltage, electrical power cannot fully be delivered to the transmission system. Fast response of the AVR and excitation system help to increase the synchronizing torque to allow the generator to remain in synchronism with the system. Field-forcing techniques are used to rapidly increase field current above the steady-state rating for a short time to increase synchronizing torque to enhance generator stability. Negative field-forcing provides fast response for load rejection and de-excitation during internal generator faults. After the short circuit has been cleared, the resulting oscillations of the generator rotor speed with respect to the system frequency will cause the terminal voltage to fluctuate above and below the AVR setpoint. AVR control limiters are used to prevent the AVR from imposing unacceptable conditions upon the generator. These controls are the maximum and minimum excitation limiters that are also discussed in Section III of this paper. The overexcitation limiter (OEL) prevents the AVR from trying to supply more excitation current than the excitation system can supply or the generator field can withstand. The OEL must limit excitation current before the generator field overload protection operates. The under excitation limiter (UEL) prevents the AVR from reducing excitation to such a low level that the generator is in danger of losing synchronism. The UEL must be coordinated with the generator capability, steady-state stability limits and loss-of-field relay as discussed in Section IV of this paper.

Using PSS to Maintain Stability

As discussed above, a fast-acting AVR is very desirable to help stabilize generator voltage during major disturbances such as fault or load rejection situations. However, these fast-acting systems can also contribute a significant amount of negative damping that results in amplifying small, low-frequency MW oscillations that can occur in a power system. These MW oscillations after a fault may vary in frequency typically from 0.1 to 2 Hz. This problem has been most often associated with the western region of the U.S. and Canada, where transmission lines connect generators to the load center over long distances. It can, however, occur anywhere the load is remote from the generation. When this occurs, the generator can eventually be driven unstable, lose synchronism and slip a pole. To address this problem, a Power System Stabilizer (PSS) is utilized in conjunction with the generator AVR to provide positive damping when megawatt oscillations occur. The PSS is a low frequency filter that prevents the AVR from amplifying low frequency MW oscillations. With the aid of a PPS, the excitation system will vary the generator field current to apply torque to the rotor to damp these oscillations. PSSs are required by NERC/Western Electric Coordinating Council (WECC) in the western U.S. and Canada for generators exceeding 30 MVA, or groups of generators exceeding 75 MVA with excitation systems installed after November 1993.

VIII CONCLUSIONS

Recent misoperations of generation protection during major system disturbances have highlighted the need for better coordination of generator protection with generator capability, generator excitation control (AVR) limiters and transmission system protection. The techniques, methods and practices to provide this coordination are well established but scattered in various textbooks, papers and relay manufacturers' literature. This paper provides a single document that can be used by relay engineers to address these coordination issues. In addition, security improvements that are made possible, and practical, through the use of digital generator protection are also highlighted.

This paper also discusses in detail the important role the generator AVR plays during major system disturbances. Since most recent major power system disturbances are the result of voltage collapse, generator protection must be secure during low-voltage system conditions while still providing generator protection. In addition, the generator AVR needs to properly control VAr support to rapidly stabilize system voltage during major disturbances. This paper provides practical guidance on proper coordination of generator protection and generator control to enhance security and system stability.

IX REFERENCES

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