COORDINATION OF GENERATOR PROTECTION WITH GENERATOR EXCITATION CONTROL AND GENERATOR CAPABILITY

Working Group J-5 of the Rotating Machinery Subcommittee,
Power System Relay Committee

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Abstract-- **This paper was written by a Working Group of the IEEE Power System Relay Committee to provide guidance to the industry to better coordinate generator protection with generator control. The paper discusses specific calculation methods that can be used to insure generator protection and excitation system control are fully coordinated. It also specifically addresses the coordination of relays with generator full load capability and machine steady state stability limits. Because of recent blackouts, NERC (North American Electric Reliability Council) is developing standards [1-3] for the coordination of generator protection and control. This paper provides practical guidance on providing this coordination.**

Index Terms-- **Automatic Voltage Regulator (AVR), NERC (North American Electric Reliability Council), Over Excitation Limiter (OEL), Under Excitation Limiter (UEL), Steady State Stability Limit (SSSL), MW-Mvar (P-Q) Diagram, Resistance-Reactance (R-X) Diagram**

I. INTRODUCTION

The need to coordinate generator protection with generator control and load capability has been well known to generator protection engineers. The techniques, method and practices to provide this coordination are well established but scattered in various textbooks, papers and in relay manufacturer's literature. In many cases these techniques, methods and practices are not well known to the practicing generator protection engineers. The purpose of this paper is to provide a single document that can be used to address coordination of generator protection with generator control. The paper uses example calculations as its means of communicating these methods. This paper also discusses steady state stability and its impact on setting generator protection.

The need to improve coordination between generator protection and control has come to light after recent misoperation of generator protection during major system disturbances. Two significant disturbances are the 1996 western area disturbances and 2003 east coast blackout.

Because of these disturbances, NERC (North American Electric Reliability Council) is asking users to verify coordination of generator protection and control [1-3]. This paper provides practical guidance for providing this coordination in the following specific protection areas:

- Generator Capability Curve Coordination
- Underexcited setting coordination with generator loss-of-field (40) protection
- Overexcited setting coordination with generator impedance (21) backup protection
- AVR Coordination - Underexcited Operation
- Coordination of the Under Excitation Limiter (UEL) with loss-of-field protection and Steady State Stability Limits
- AVR Coordination – Overexcitation Operation
- Coordination of AVR V/Hz limiter with overexcitation (V/Hz) protection

II. GENERAL DISCUSSION OF GENERATOR CAPABILITY AND EXCITATION CONTROL

A. Excitation Control Basics

The excitation system of a generator provides the energy for the magnetic field (satisfying magnetizing reactance) 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. Increasing the excitation 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 excitation system help to increase the synchronizing torque to allow the generator to remain in synchronism with the system. 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 set point. Excitation controls are called upon to prevent the AVR from imposing unacceptable conditions upon the generator. These controls are the maximum and minimum excitation limiters. 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, exceeding machine under-excited capability, or tripping due to exceeding the loss of excitation protection setting. The UEL must prevent reduction of field current to a level where the generator loss-of-field protection may operate.

B. Generator Steady State Stability Basics

Steady state instability occurs when there are too few transmission lines to transport power from the generating source to the load center. Loss of transmission lines into the load center can result in steady state instability. Fig.1 illustrates how steady state instability occurs for a simplified system with no losses. The ability to transfer real (MW) power is described by the power transfer equation below and is plotted graphically in Fig. 1.

$$Pe = \frac{Eg \quad Es}{X} \operatorname{Sin}(\theta g - \theta s)$$

Where: Eg = Voltage at Generation
Es = Voltage at System
Pe = Electrical Real Power Transfer
X = Steady State Reactance Between Generator and System
θg = Voltage Angle at Generation
θs = Voltage Angle at System

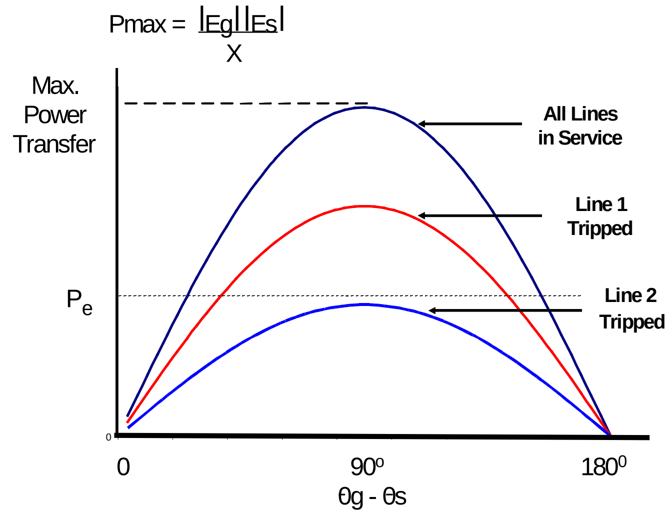

Fig. 1 Power Angle Analysis - Steady State Instability

From the power transfer equation above it can be seen that the maximum power (Pmax) that can be transmitted is when θg-θs = 90^0 i.e. sin 90^0 = 1. 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. If enough lines are tripped between the load center and remote generation supplying the load center the reactance (X) between these two sources increases to a point where the maximum power (Pmax), which can be transferred, is insufficient to maintain synchronism. The power angle curve in Fig. 1 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 unit goes unstable. During unstable conditions generators may slip poles and lose synchronism. Voltage collapse and steady state instability can occur together as transmission lines tripping increase the reactance between the load center and remote generation. A graphical method can be used to estimate the steady state stability limit for a specific generator. This method is discussed in Section IV of this paper.

C. Generator Watt/var Capability

A typical cylindrical rotor generator capability curve is shown in Fig. 2. The capability curve establishes the steady state (continuous) generator operating limits. The generator capability curve is normally published at generator rated voltage. Salient pole generators have a slightly different characteristic in the underexcited region. The curve also shows how the AVR control limits steady state operation to within generator capabilities. The generator capability (Fig.2) 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.

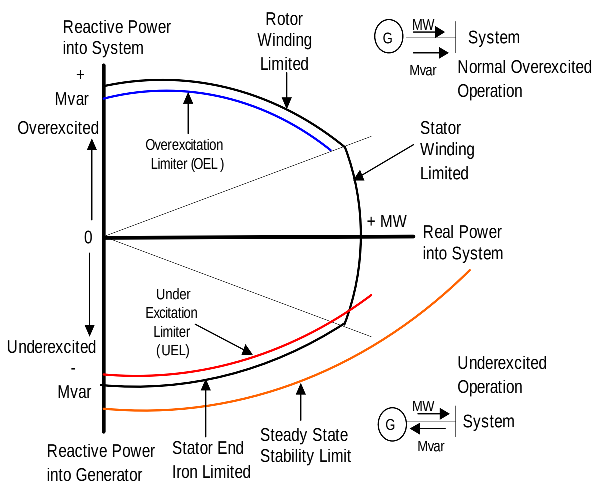

Fig 2. Typical Generator Capability Curve and Operating Limits for a cylindrical rotor generator

The rotor winding 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 excitation control limiters are intended to limit operation of the generator to within its continuous capabilities. Fig 2 illustrates how these limiter setpoints can be plotted on a typical generator capability curve. Generally, the setting of the UEL control will also coordinated with the steady-state stability limit of the generator which is a function of the generator impedance, system impedance and generator terminal voltage. This section of the paper discusses steady state stator stability in general terms. The next sections of this paper will outline a conservative graphical method for estimating the steady state stability limit for a generator as well as a specific example.

The overexcitation control (OEL) limits generator operating in the overexcited region to within the generator capabilities curve. Some users set the OEL just over the machine capability curve to allow full machine capability and to account for equipment tolerances, while others set it just under the capability curve as shown in Fig 2.

Engineers should be aware that more restrictive limits of generator capability could be imposed by the power plant auxiliary bus voltage limits (typically +/- 5%), the generator terminal voltage limits (+/-5%), and the system generator high voltage bus minimum and maximum voltage during peak and light load conditions. The high and low voltage limits for the auxiliary bus, generator terminal and system buses are interrelated by the tap position selected for the generator step up transformer and the unit auxiliary transformer. Consequently, as power system operating change, it is necessary to check tap setting to ascertain that adequate reactive power is available to meet power system need under emergency conditions.

D. P-Q to R-X Conversion

Both Figures 2 and 3 illustrate the capability of a generator on a MW-Mvar (P-Q) diagram. This information is commonly available from all generator manufactures. 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 coordinate the generator capability with these impedance relays, it is necessary to either convert the capability curve and excitation limiters (UEL and OEL) to an R-X plot or to convert impedance relay settings to a MW-Mvar plot. Figure 3 illustrates this conversion [4]. 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.

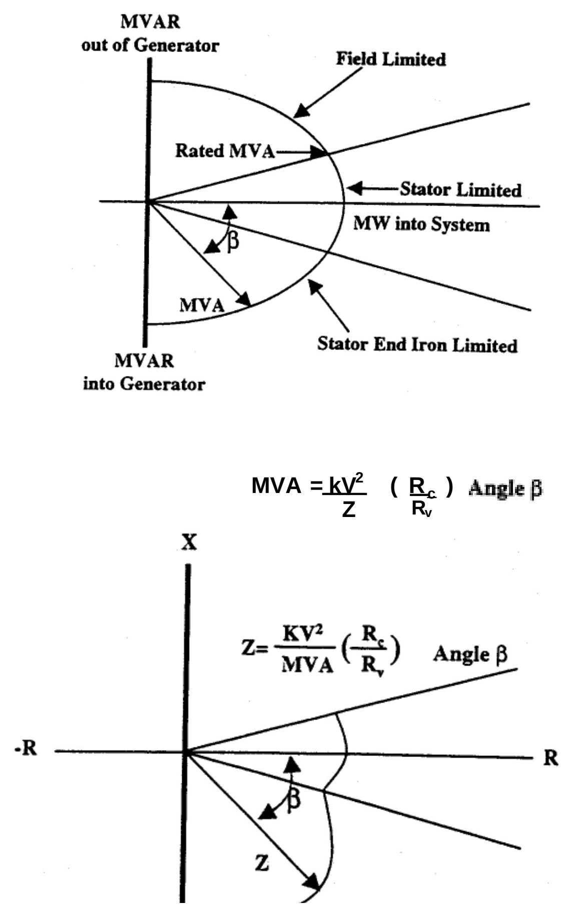

Fig. 3 Transformation from MW- Mvar to R-X and R-X to MW-Mvar Plot

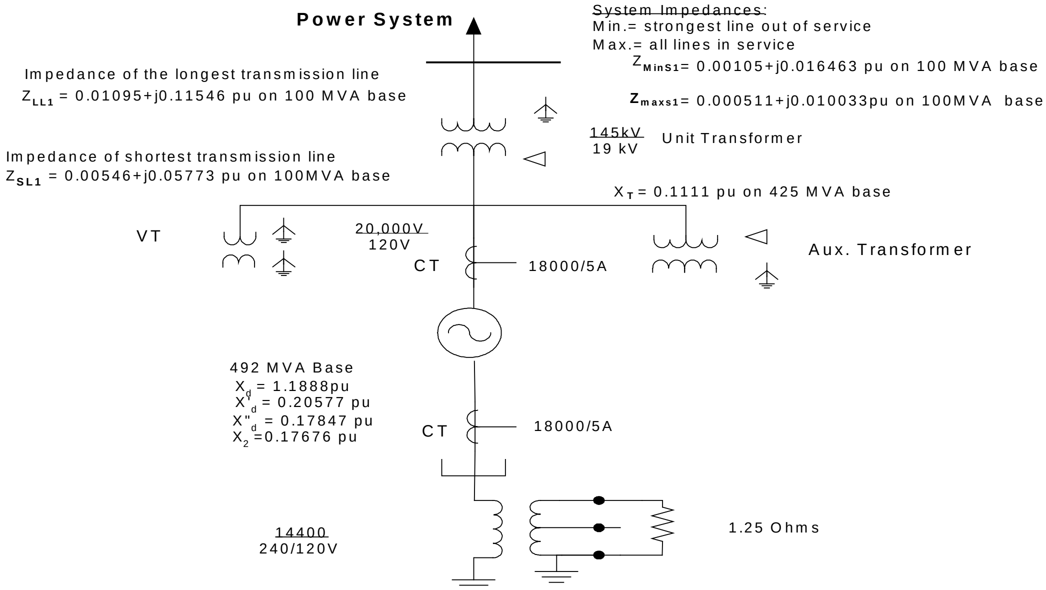

Fig.4 One line diagram with generator and power system data for example generator

III. BASIC MACHINE AND SYSTEM DATA FOR EXAMPLE CALCULATION

A 492 Mva, 20kV direct cooled cylindrical rotor steam turbine rated at 14202A, 0.77PF has been selected as the sample generator to demonstrate the calculation methods to provide coordination of generator AVR control, machine capability and steady state stability limit with relay protection. Fig. 4 shows the basic one line diagram as well as machine and system impedance data that are required for the example calculations. The unit transformer in this example is 425MVA, Y-grounded/delta whose tap are set at 145/19kV. Fig 5 shows the generator capability curve for the example machine. Key symbols used in calculation are defined in Appendix I.

IV. AVR COORDINATION- UNDEREXCITED OPERATION

Excitation systems seldom operate at the extremes of their capabilities until the system voltage attempts to rise or fall outside its normal operating range. During voltage transients, excitation controls allow short-term operation of the excitation system and generator beyond the rated steady state limits. The excitation system controls and protective relays must coordinate with regard to both pickup magnitudes as well as time delays.

The setting of the under excitation limiter takes into consideration the generator capability curve and the setting of the loss-of-field relay (see Section V) plus the characteristics of the under excitation limiter itself. These characteristics vary with each generator and system configuration. The automatic voltage regulator uses the generator terminal voltage and phase current to calculate the existing operating conditions. By comparing the actual point of operation to the desired limit,

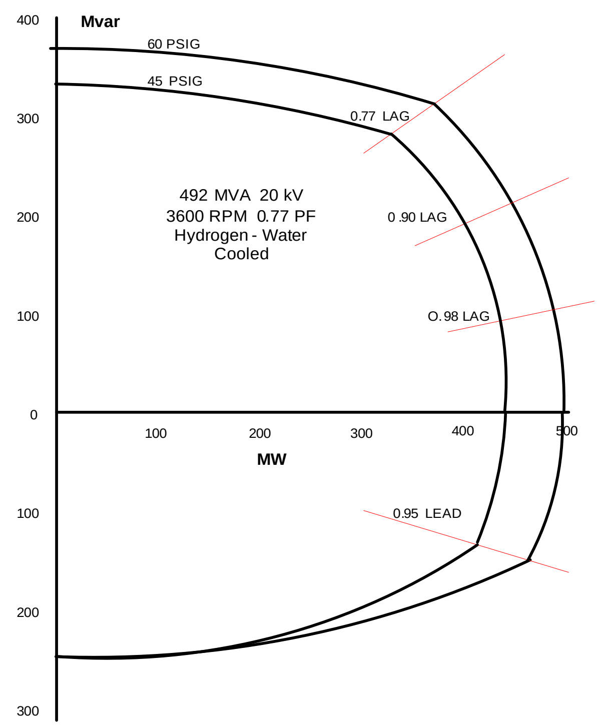

Fig 5 Generator Capability Curve for Example Generator

the regulator determines when it is appropriate to adjust the generator field current in order to remain within the desired operating conditions. Alternatively, discrete relays have also been applied to motor operated rheostat excitation systems. These relays operate similarly to the above automatic regulator function, measuring generator voltage and current to determine the actual operating condition, and then initiating a control signal when the limit setting is exceeded. It should be noted that the limit settings can change with voltage. Some 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 voltage variation characteristic should be identified when setting the limiter. Manual regulators do not have under excitation limiters as an active component. The process for establishing the underexcitation limit and checking the coordination is as follows:

1. Obtain the generator capability curve.
2. Obtain the step-up transformer impedance (X_T), generator synchronous (Xd) and transient reactance (Xd').
3. Determine the equivalent system impedance typically with the strongest source out-of-service.
4. Calculate the steady state stability limit and plot on the generator capability curve.
5. Calculate the loss-of-field relay setting and plot on the generator capability curve. This setting should be adjusted, depending upon the steady state stability curve and the generator capability curve (see Section V).
6. Determine the most limiting condition(s), considering the generator capability curve, the steady state stability curve and the loss-of-field relay characteristic.
7. Determine the under excitation limiter setting.
8. Verify that the impedance loci do not swing into the relay impedance characteristic, causing a false trip for a stable system transient. This generally requires transient stability studies.
9. Determine the time delay, based upon the excitation system time constants and the characteristics of the system swings. Verify the coordination between the under excitation limiter setting and the loss-of-field relay settings.

A. Steady State Stability Limit (SSSL) - Graphical Method

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 system. This method assumes field excitation remains constant (no AVR) and is conservative. NERC explicitly requires that generators operate under AVR control, which improves the stability limit. When making the calculations, all impedances should be converted to the same MVA base, usually the generator base. The steady state stability limit is a circle defined by the equations shown in Fig. 6 below [4]:

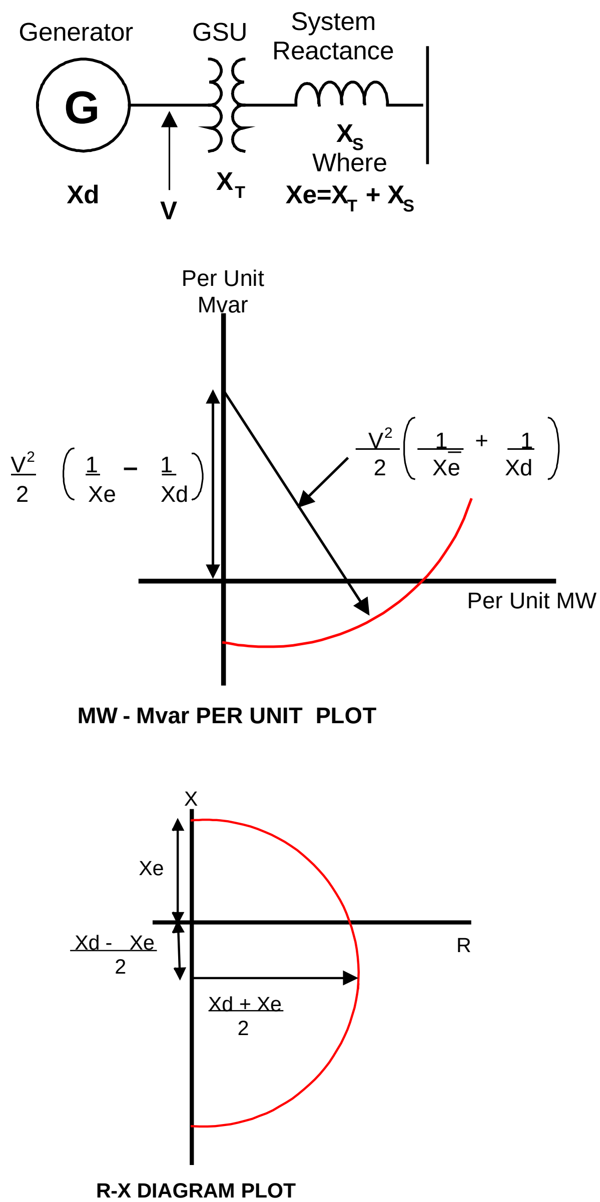

Fig. 6 Graphical Method for Steady State Stability

Where Xd = generator synchronous reactance
Xs = equivalent system reactance
Xe = the sum system and step-up transformer reactance ($Xs + X_T$)
V = generator terminal voltage

The graphical method shown in Fig. 6 is widely used in the industry to display the steady state stability limit on P-Q and R-X diagrams. 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 times, the system reactance model will consist of the normal system without the single strongest line from the external system. This provides a setting still valid for any line out of- service. In most cases, the steady state stability limit is outside the generator capability curve, and does not restrict generator operation.

B. Steady State Stability Limit (SSSL) Calculation Example and UEL Setting.

1. Generator and system data are shown in Fig. 4 and the generator capability curve in Fig. 5.

2. The step-up transformer reactance is given as 0.1111 pu on a 425 MVA base. The generator synchronous reactance is 1.18878 pu on a 492 MVA base. The generator transient reactance is 0.20577 pu. The transformer impedance on the generator base is 0.11607 pu as calculated below:

$$X_{TG} = \frac{MVA_G}{MVA_T} * \frac{kV_{Tlow}^2}{kV_S^2} * X_T$$

$$X_{TG} = \frac{492}{425} * \frac{19^2}{20^2} * 0.111 = 0.11607$$

3. The system impedance (with the strongest source out of service) is $X\min_{S1}$ = j0.016463 pu on a 100 MVA base. The system voltage base is 138kV, which is different than the transformer's 145kV high side tap. Therefore to account for the difference in the voltages, the impedance has to be adjusted as the square of the voltages ($138^2/145^2$) as shown below:

$$X\min_{ST1} = \frac{MVA_G}{MVA_S} * \frac{kV_S^2}{kV_{Thigh}^2} * X\min_{S1}$$

$$X\min_{ST1} = \frac{492}{100} * \frac{138^2}{145^2} * 0.016463 = 0.07338\,pu$$

The impedance then must be converted from the transformer voltage base to the generator voltage base.

$$X\min_{SG} = \frac{kV_{Tlow}^2}{kV_G^2} * X\min_{ST1}$$

$$X\min_{SG} = \frac{19^2}{20^2} * 0.07338 = 0.06621\,pu$$

4. To calculate the steady state stability limit on a P-Q diagram use the equations in Fig 6. $Xe = X_{TG} + X\min_{SG1}$ = 0.11607pu+0.06621pu =0.18238 pu. The generator synchronous impedance, Xd, is 1.18878 pu (see Fig.4).

$$\text{Center} = \frac{V^2}{2}\left(\frac{1}{Xe} - \frac{1}{Xd}\right) = \frac{1}{2}\left(\frac{1}{0.1824} - \frac{1}{1.18878}\right)$$

= 2.31pu of 492 MVA or 1142 MVA

$$\text{Radius} = \frac{V^2}{2}\left(\frac{1}{Xe} + \frac{1}{Xd}\right) = \frac{1}{2}\left(\frac{1}{0.1824} + \frac{1}{1.18878}\right)$$

= 3.162pu of 492 MVA or 1556 MVA

Using the equations for the center and the radius in Fig. 6. the center is at 1142 on the positive Mvar axis, and the radius is 1556MVA. The intercept point on the negative Mvar axis is at –414Mvar (1556-1142). The P-Q plot is shown below in Fig. 7. Fig. 7 also shows the UEL and generator capability (GCC) on the P-Q plot.

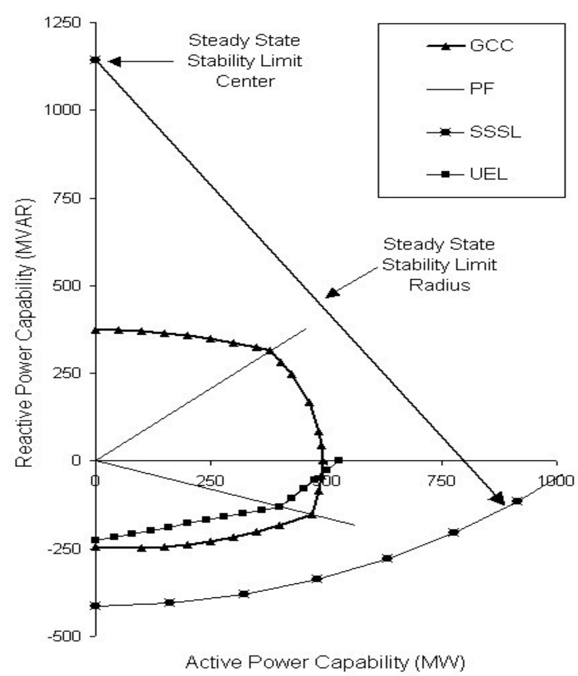

Fig.7 Generator Capability (GCC), Underexcitation Limiter (UEL) and Steady State Stability Limit (SSSL) for Example Generator – P-Q Plot

5. From Fig. 2, generally the stator end iron limit on the generator capability curve is the most limiting condition, compared to the steady state stability limit or the loss-of-field relay characteristic.

6. The under excitation limiter (UEL) should be set to operate prior to reaching the stator end iron limit. Assuming that the plant operates between H_2 pressures of 45psig and 60psig, use a margin of 10% of the leading Mvar limit (machine end turn limit or steady state stability limit, whichever is most limiting) at various MW points. The example limiter has three set points, one on the negative var axis, one on the positive Watt axis, and one defined with both a Watt and var point. All points are expressed as per unit on the generator MVA base. They should be selected to allow the greatest range of generator operation as possible. The points (vars pu, Watts pu) will be (0.45, 0), (0.27, 0.81) and (0, 1.12). They are plotted on Fig. 7 in Mvar and Mw values using the 492 MVA base.

7. The under excitation limiter time delay should be minimal. Some limiters do not have an intentional delay, but utilize a damping setting or circuit to stabilize the limiter output. In addition, there may be a setting to proportionally increase the limiter output, dependant upon the severity of the underexcitation condition (increased output for a more severe condition). The limiter manufacturer should be consulted for these parameters.

V. GENERATOR LOSS OF FIELD COORDINATION

To limit system voltage the 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 under excitation limiter (UEL) must be set to maintain operation within the capability curve as show in Fig. 2. The loss of field relay must be set to allow the generator to operate within its underexcited capability.

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 iron. The high reactive current drawn by the generator from the power system can overload the stator windings. These hazards are in addition to the previously mentioned stator end-iron damage limit.

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. There are two basic designs of this type of protection.

The first method (Scheme 1 –Fig.8) consists of two offset Mho units. An impedance circle diameter equal to the generator synchronous reactance and offset downward by ½ of the generator transient reactance 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 swing. A second relay zone, 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 is used also. This Zone 1 element has a few cycles of delay and more quickly detects severe underexcitation conditions. When synchronous reactance is less than or equal to 1.0 per unit (e.g. hydro generators) only the Zone 2 is used and is set with the diameter equal to 1.0 per unit.

The second relaying method (Scheme 2 – Fig.10) consists of an undervoltage unit, an impedance unit and a directional unit. In this case the generator synchronous and transient reactances are used to determine the settings. As with the first scheme, two elements are used, one without significant delay (typically 0.25 second for the most severe condition) and the other delayed to prevent misoperation. For both schemes the relay settings are based on ct and vt secondary quantities, thus the impedances need to be calculated on the ct and vt secondary basis.

A. Loss of Field Calculation Example

Scheme1: In this example, two mho characteristics are used. Standard settings for this two zone loss-of-field scheme are shown below in Fig.8.

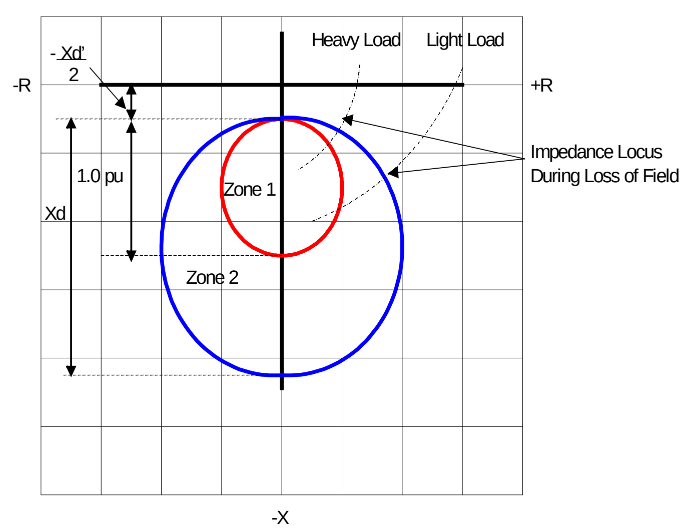

Fig. 8 Loss-of-Field R-X Diagram -- Scheme 1

The zone 2 element is set at a diameter of Xd or 1.18878 pu and the Zone1 diameter would be set at 1.0 pu on the generator base. Both units are offset by X'd/2.The generator data is shown in Fig.4.The formula to convert the generator impedances (which are in pu) to relay secondary ohm is shown below:

$$X\ \sec = \frac{kV^2 * X_{PU}}{MVA} * \frac{R_C}{R_V}$$

Where: Xsec = Relay Secondary Ohms
kV = Generator Rated Voltage
Xpu = pu Reactance
MVA = Generator Rated MVA
Rc = CT ratio
Rv = VT ratio

Zone 1

Diameter of the circle is set at 1.0 pu or 17.56 Ω

Offset of the circle X'_d/2 is 0.20577/2 pu or -1.8067 Ω

Time delay: A short time delay of approximately 3 to 5 cycles is suggested to prevent misoperation during switching transients.

Zone-2

Diameter of the mho circle is set at X_d = 1.1888 pu or 20.88 Ω .Offset of the mho circle is set the same as for Zone 1 or -1.8067 Ω

Time delay: A minimum time delay of 30 to 45 cycles is typically used to prevent relay misoperation during stable power swing conditions. In cases where only one mho element is used, the methodology for Zone 2 above is typically employed.

Fig. 9 shows the loss of field relay characteristics along with generator capability curve (GCC), the under excitation limiter (UEL), and the steady state stability limit (SSSL) plotted on the R-X plane. The GCC, UEL curves are converted from P-Q plane to R-X plane using the calculation method described in Fig.3.

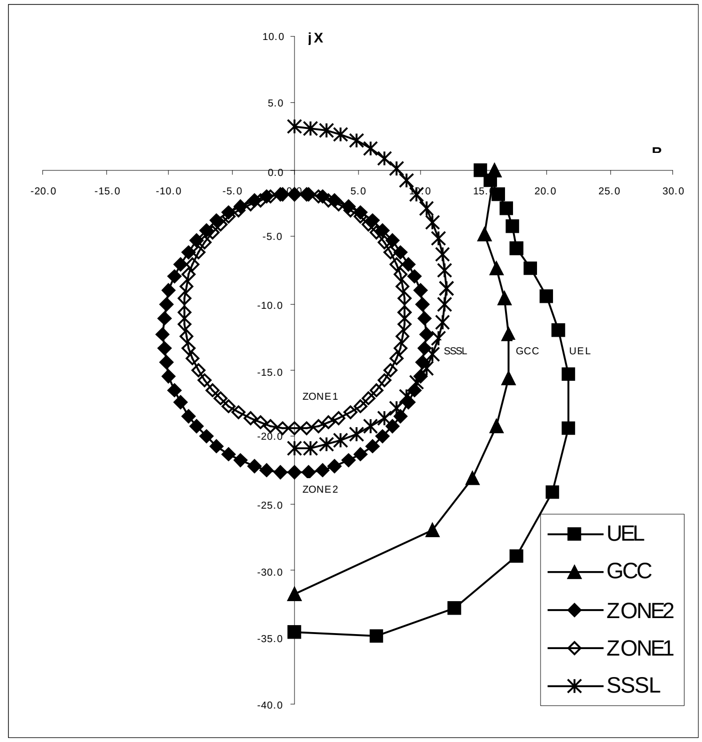

Fig 9 Loss-of- Field, Scheme 1, R-X Plot

Scheme2: This scheme also uses both Zone 1 and Zone 2 elements. Standard settings for this two zone loss-of-field scheme are shown below in Fig.10:

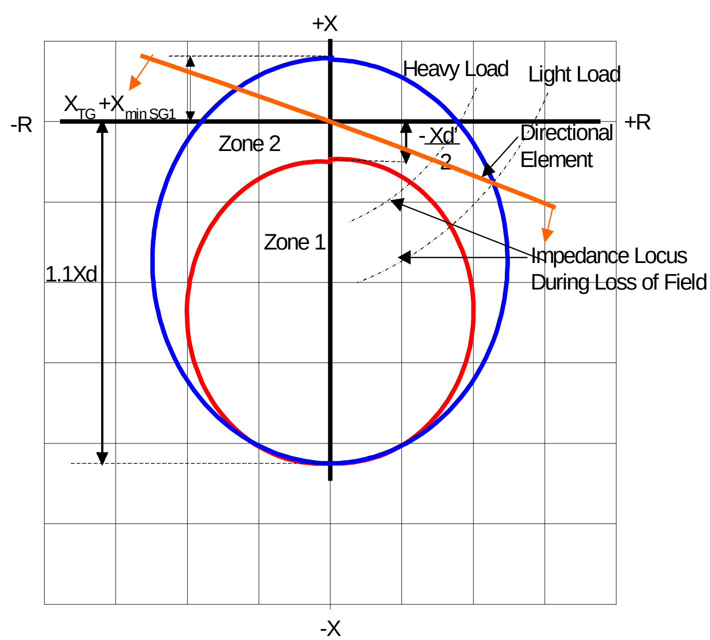

Fig. 10 Loss -of-Field R-X Diagram -- Scheme 2

Scheme 2 uses a combination of two impedance elements, a directional unit and an undervoltage unit applied at the generator terminals. The Zone 2 element is set to coordinate with the Steady State Stability Limit. The top of the Zone 2 circle (positive offset) is set at the system impedance in front of the generator. Typically, this will be the generator transformer reactance X_{TG} + X_{minSG1}. X_{minSG1} is the weak source (with the strongest line out of service) system impedance on the generator base. The transformer and system impedance must be put on the same base as the generator. The negative reach is set to at least 110% of Xd to encompass the SSSL with margin. The negative reach of Zone 1 element is then set to match. The negative offset of Zone 1 element is set to X'd/2 to establish the top of the circle.

Since the Zone 2 element has a positive offset it is supervised by a directional element (DE) to prevent pickup for system or unit transformer faults. The directional element is typically set at an angle of between 10 and 20 degrees. This unit is usually set at 13°. The Zone 2 time delay is typically set at 10 sec. to 1 minute. A loss of field condition is generally accompanied by low generator terminal voltage. For this condition an undervoltage relay is used to reduce the Zone 2 time delay. The drop out of the undervoltage unit is typically set at 0.80-0.87 pu which will cause accelerated Zone 2 tripping with a time to 0.3-0.2 sec. Transient stability studies can be used to refine the voltage supervision and time delay settings.

Zone-2

Diameter is typically set to 1.1 times X_d plus the weak system source and step-up transformer impedances .The 110% multiplier on X_d provides a margin to pickup before reaching the steady state stability limit. In this application, there is a large separation between the SSSL and the GCC. In order to provide better protection for under-excited operation of the unit, the margin can be set to 125%, which moves the characteristic to approximately half way between the SSSL and the GCC curves.

Diameter of the circle in pu:

$$Z2_{Diameter} = 1.25 * X_d + X_{TG} + X\min_{SG}$$

$$Z2_{Diameter} = 1.25*1.1888 + 0.1161 + 0.0662$$

$$Z2_{Diameter} = 1.6683 \text{ or } 29.3\ \Omega$$

Zone 2 Offset: Set the Zone 2 offset to the system source impedance (Reactance) as seen from the terminals of the unit.

$$Z2_{Offset} = X_{TG} + X\min_{SG}$$

$$Z2_{Offset} = 0.1161 + 0.0662$$

$$Z2_{Offset} = 0.1823 \text{ or } 3.2\ \Omega$$

Zone 2 Directional Supervision: Since the Zone 2 element has a positive offset; it is supervised by a directional element (DE) to prevent pickup of the element for system or unit transformer faults. Set the directional element to 13 degrees.

Zone 2 Delay: Set the Zone 2 delay long enough that corrective action may take place to restore excitation before the unit goes unstable. Settings of 1 second to 1 minute are appropriate. Since two zones are used, the delay will be set to 10 sec.

Phase Undervoltage Element: An under-excitation condition accompanied by low system voltage caused by the system's inability to supply sufficient Vars will cause the unit to go unstable more quickly. For this condition, an undervoltage unit is used to bypass the Zone 2 time delay for low system voltage. The drop out of the undervoltage unit is typically set at 0.8 pu which will cause accelerated Zone 2 tripping with a time delay of 0.25 sec.

Zone-1

Zone 1 Diameter: Set to same negative reach as Zone 2 of X'd/2.

Diameter of the circle in pu:

$$Z1_{Diameter} = 1.25 * X_d - \frac{X'_d}{2}$$

$$Z1_{Diameter} = 1.25*1.1888 - \frac{0.20577}{2}$$

$$Z1_{Diameter} = 1.3831 \text{ or } 24.3\ \Omega$$

Zone 1 offset: Set to one half of the generator transient reactance.

$$Z1_{Offset} = -\frac{X'_d}{2}$$

$$Z1_{Offset} = -\frac{0.20577}{2}$$

$$Z2_{Offset} = -0.102885 \text{ or } -1.806\ \Omega$$

Fig. 11 shows the loss of field relay characteristic for Scheme 2 with the generator capability curve (GCC), the under excitation limiter (UEL) and steady state stability limit (SSSL).

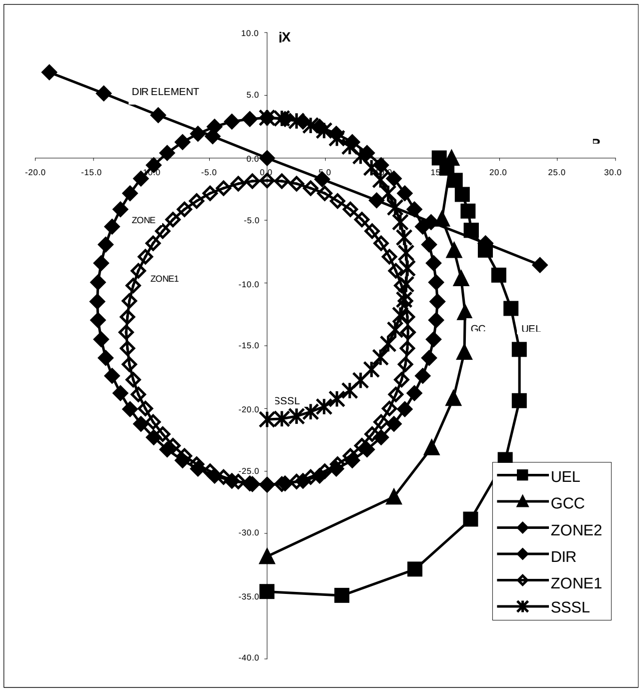

Fig 11 Loss-of- Field, Scheme 2, R-X Plot

VI. GENERATOR PHASE BACKUP (21) COORDINATION

The primary purpose of the phase distance (21) relay is to protect the generator from supplying prolonged fault current to fault on the power system to which the generator is connected. A mho characteristic is commonly used to detect system phase faults and to separate the generator after a set time delay. The relay's impedance reach and time delay settings must be coordinated with transmission system primary and backup protection to allow selectivity. Typically, the phase distance relay's reach begins at the voltage input to the relay and extends the length of the longest line out of the transmission substation. Some factors involving the settings are as follows:

1. *In-feeds:* Apparent impedance due to in-feeds will require larger reaches; however, settings to cover long lines may overreach adjacent short lines.
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 relay to respond to faults at the end of the longest lines is mitigated.
3. *Load Impedance:* Settings should be checked to ensure the maximum load impedance ($Z_{max/Load}$ =kV^2/ MVA at rated power factor angle (RPFA) does not encroach into the reach. A typical margin of 150-200 % at rated power factor is recommended 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 95 percent of nominal ratings [5]. Utility transmission planners should be consulted for worst case emergency voltage levels at power plants.

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. Set to respond to faults 80% of the Zone 1 setting of the shortest transmission line exiting the power plant (neglecting in-feeds) plus step-up transformer impedance. Some users apply Zone 1 as a backup to generator bus work and GSU protection with typical settings of 50-80% of the GSU impedance.

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. Stability studies may be required to insure that Zone 1 unit does not trip for stable power swings.

The Zone 2 relay element is typically set at the smaller of the three following 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 limiting criteria.
3. 80 to 90 % of generator load impedance at the maximum torque angle of the Zone 2 impedance relay setting (typically 85^0).
4. Time delay to coordinate with transmission system backup protection and local breaker failure.

A. Zone 1 Setting Example

Set zone 1 using the smaller of the two criteria:

<u>Criteria 1</u>

120% of the unit transformer (X_{TG})

Converting X_{GT} to secondary ohms

$$X_{TG\sec} = \frac{kV_G^2 * X_{TG}}{MVA_G} * \frac{R_C}{R_V}$$

$$X_{TG\sec} = \frac{20^2 * 0.11607}{492} * \frac{18{,}000/5}{20{,}000/120}$$

$$X_{TG\sec} = 2.038\Omega$$

$$Z1_{reach} = 1.20 * 2.038 = 2.45\Omega$$

Criteria 2

Set at 80% of the Zone 1 setting of the shortest line plus step-up transformer impedance. The impedance of the shortest line exiting the power plant is $X_{SL1} =$ j 0.05773 pu on a 100MVA base. The zone 1 line setting is 80% of the line length. First put the impedance on the generator base.

$$X_{SLG} = \frac{MVA_G}{MVA_S} * \frac{kV_S^2}{kV_{Thigh}^2} * \frac{kV_{Tlow}^2}{kV_G^2} * X_{SL1}$$

$$X_{SLG} = \frac{492}{100} * \frac{138^2}{145^2} * \frac{19^2}{20^2} * 0.05773$$

$$X_{SLG} = 0.23219 \text{ pu}$$

Converting the line impedance to secondary relay ohms.

$$X_{L1\sec} = \frac{kV_G^2 * X_{SLG1}}{MVA_G} * \frac{R_C}{R_V}$$

$$X_{L1\sec} = \frac{20^2 * 0.23219}{492} * \frac{18{,}000/5}{20{,}000/120}$$

$$X_{L1\sec} = 4.077\Omega$$

Assuming the zone 1 line setting is 80% of the lines then:

$$Z1_{reach} = X_{TG\sec} + 0.8 * (0.8 * X_{L1\sec})$$

$$Z1_{reach} = 2.041 + 0.8 * (0.8 * 4.077) = 4.6095\Omega$$

Set the zone 1 at the smaller setting of 2.45 Ω at a MTA of 85^0.

B. Zone 2 Setting Example

Criteria 1

The apparent impedance reach (Z_{2_LINE}) to the end of the longest line exiting the plant will require an in-feed calculation because both the generator and the utility transmission system will contribute fault current. The saturated value of transient reactance X'd is used in this calculation since this is for a time delayed backup element.

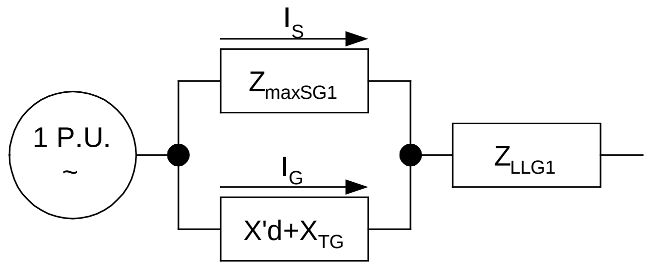

Fig. 12 Equivalent Circuit for Apparent Impedance with In-Feeds

$$Z_{Total} = \frac{1}{\frac{1}{Z_{\max SG1}} + \frac{1}{X'_d + X_{TG}}} + Z_{LLG1} =$$

0.04566 + j0.50024 pu

$$I_{Total} = \frac{1}{Z_{Total}} = 0.18097 - j1.98253 \text{ pu}$$

Current Divider Rule:

$$I_S = \left| I_{Total} \text{ x } \frac{X'_d + X_{TG}}{X'_d + X_{TG} + Z_{MaxSG1}} \right| =$$

1.76895 pu

$$I_G = \left| I_{Total} \text{ x } \frac{Z_{MaxSG1}}{X'_d + X_{TG} + Z_{MaxSG1}} \right| =$$

0.22207 pu

Based on the criteria 1 for the Zone 2 element setting:

$$Z_{2\_LINE} = \left(X_{TG} + 1.2\left(\frac{I_S + I_G}{I_G}\right) Z_{LL1G} \right) \text{ x } Z_{B\_relay} =$$

90.2 Ω ∠ 85°, maximum torque angle Zone 2 (MTA2) = 85°

Criteria 2

To satisfy criteria 2, the reach of the 21-2 element should not exceed 50% to 66.7% (200% to 150% of the generator capability curve) load impedance at rated power factor. Otherwise the distance element could trip on load or stable power swings. This calculated is shown below:

$$Z_{\max\ load} = \frac{kV_G^2}{MVA_G} \frac{CT_{Ratio}}{VT_{Ratio}} = 17.56\ \Omega\ \angle 39.64^\circ\ (0.77\text{pf})$$

The Z_2 reach setting at MTA based on $Z_{\max\ loading}$ based on $Z_{\max\ load}$ above is:

$$Z_{2\_MTA} = 0.67\text{x}\frac{Z_{\max\_load}}{COS(MTA2 - RPFA)} = 16.6\Omega\angle 85°;$$

where RFPA is the rated power factor angle.

Criteria 3

The reach of the 21-2 element should not exceed 80% to 90% (125% to 111% of the generator capability curve) load impedance at maximum torque angle. Otherwise the distance element could limit the generator capability curve. This can be calculated as:

$$Z_{GCC\_MTA} = \frac{kV_G^2}{MVA_{GCC\_MTA}} \frac{CT_{Ratio}}{VT_{Ratio}} = 23.14\ \Omega \quad \angle 85°$$

$$Z_{2\_MTA2} = 0.9 \text{ x } Z_{GCC\_MTA} = 20.8\Omega \angle 85°$$

Since criteria 2 gives the smallest reach setting, the 21-2 setting should be set at 16.6Ω at the MTA of 85^0 to provide a secure setting. This is much less than the 90.2 Ω reach required to respond to faults at the end of the longest line. For this case, upgrading of the backup protection on the transmission system should be investigated to provide proper primary and backup protection as well as local breaker failure. For this case, upgrading of the backup protection on the transmission system should be investigated to provide proper primary and backup protection as well as local breaker failure. In this case the desired generator remote backup cannot be provided without compromising loadability. Fig. 13 shows the distance elements and generator capability curve plotted on an R-X diagram.

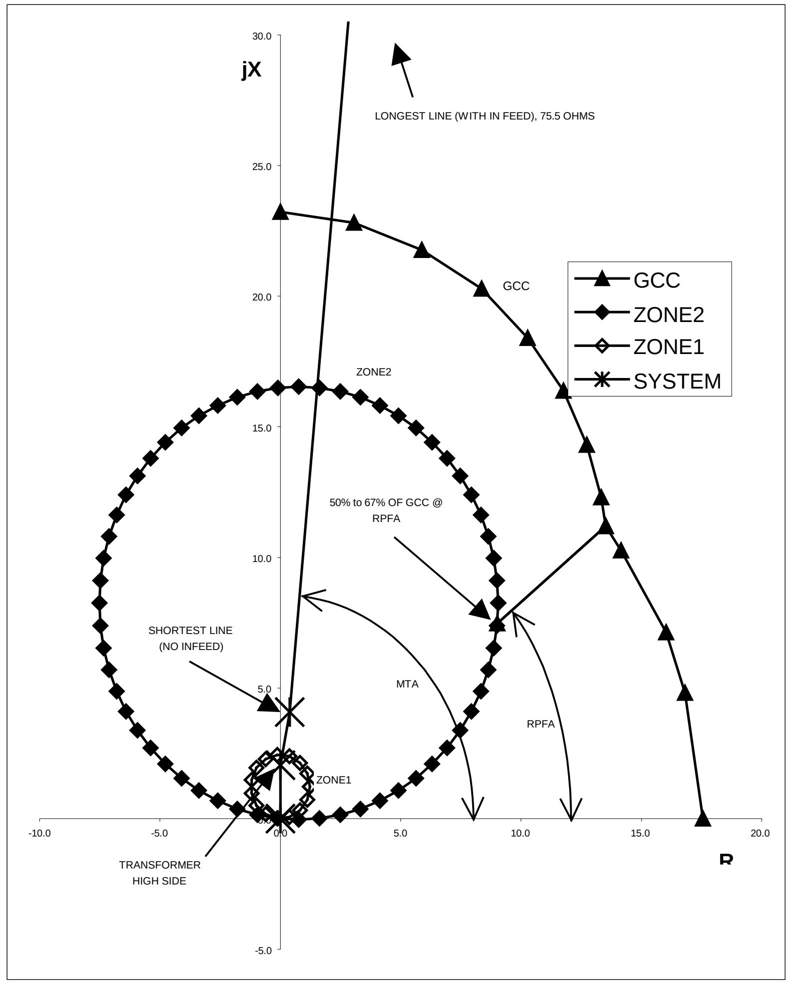

Fig.13 21 Distance Setting Examples Plotted on an R-X Diagram

VII. AVR COORDINATION- OVEREXCITED OPERATION

Excitation system protection/control as well as protection external to the excitation system needs to be coordinated so as not to limit the generator overexcitation capability. During major system disturbances, the excitation control/ protection must allow the generator to operate within its short time capabilities.

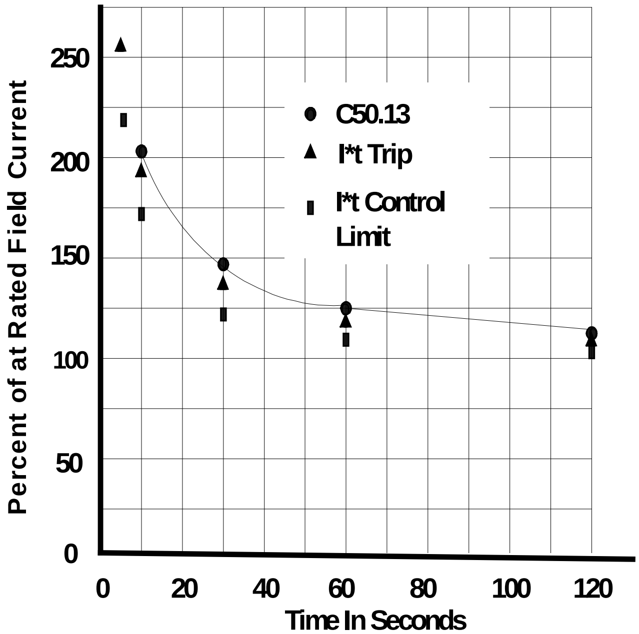

Fig. 14 C50.13 Cylindrical-Rotor Field Short Time Capability [7] and Typical Limiter Control and Trip Coordination [13]

System var support provided by the generator is extremely important to maintain power system voltage stability. IEEE C50.13 [7] defines the short-time field thermal capability for cylindrical-rotor generators. In this standard the short time thermal capability is given in terms of permissible field current as a function of time. A plot (curve drawn from data in C50.13) of this short time capability is shown in Fig.14.

Present-day exciters fall into two broad categories: those using AC generators (alternators) as a power source and those that use transformers. Because the protection requirements of the excitation system are closely related to their design, the field protection equipment is normally provided as part of the excitation system. Data for the specific generator field capability need to be used in determining excitation capability and coordination. It is important that the control as well as any tripping protection that maybe embedded within the exciter allow the generator to provide full overexcitation system support during system voltage transient as well as for steady state conditions. As discussed in Section II of this paper, the selection of the step-up transformer tap setting play a key role in determining whether the generator can provide it's full var support to the system without being limited by the generator terminal voltage. Generally, in the US generator step-up transformers are not equipped with LTC load tap changing. Consequently, as power system operating conditions change over time, it is necessary to periodically check that optimum transformer tap settings have been selected [12]. Such checks are typically done by system planning engineers who determine optimum tap settings from load flow studies.

Another important factor that must be incorporated into the design of the excitation protection/control system is the need to accommodate field forcing during faults to aid in maintaining transient stability. This dictates that very high rotor field current (typically in the range of 140-280% of rating) must be permitted to flow for a short period of time without causing the exciter control to reduce field voltage because of the high field current.

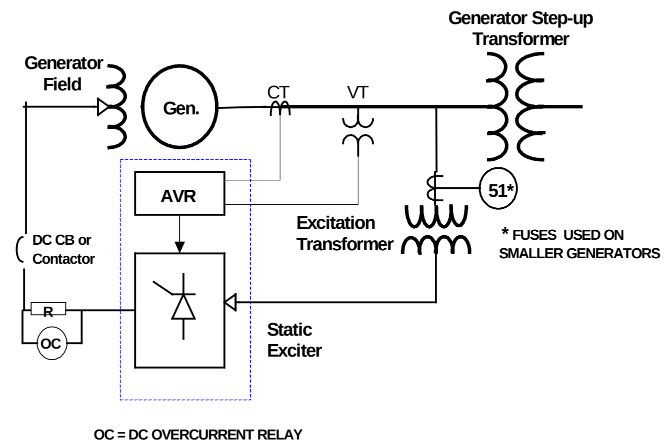

Fig. 15 Typical Transformer Supplied Excitation System

Field forcing times are typically at least 1 second but may be as long as 10 seconds for compound or brushless excitation systems. [13]. Fig. 15 illustrates a typical transformer supplied static excitation system with the excitation transformer connected to the generator terminals. Excitation systems have controls and limiters that are designed to protect the field from thermal damage due to prolonged exposure to high current or overexcitation due to higher than allowable flux (V/Hz) levels. Typically key protection/control elements within the excitation system that affect overexcitation generator operation include:

- <u>Overexcitation Limiter (OEL)</u> – Protects the generator field circuitry from excessive current versus time heating. Its setting should be coordinated with the generator capability in the overexcitation region as described in Section II of this paper so that full var capability of the generator is available. The setting should also allow the exciter to respond to fault conditions where field current is boosted (field forcing) to a high level for a short period of time. In many cases this coordination is provided by not enabling OEL control until the field forcing time is exceeded. The OEL setting should also allow utilization of the short time field current capability as defined by C50.13 (Fig. 14 for cylindrical rotor generators). Typically, the OEL takes over control to limit field current from the steady state AVR control for close in faults where the induced field current remains high or during sustained system low voltage conditions requiring field current above rated levels. In new excitation systems the OEL limiter control has the ability to modify its setting based on either hydrogen pressure (if the generator is hydrogen cooled) or inlet air temperature measurements.

- V/Hz Limiter – Limits the generator V/Hz ratio by limiting the generator voltage to a programmed setting. Steady state limit are +/- 5% of rated generator stator terminal voltage at rated frequency. The setting should permit short time excursions during transient conditions. The V/Hz limiter is a limit function to the AVR setpoint and is not a variable as is the above described OEL in Fig.14.
- Field Overcurrent Protection – DC overcurrent protection is provided in exciters as show in Fig. 15. Some exciters have a protective inverse time module that calculates the I*t to provide an inverse time curve. It needs to be coordinated with the OEL setting as well as the short time capability of the field (Fig. 14). It also should allow field forcing to take place during fault conditions. In some cases this protection may trip the exciter if OEL initiated runback is unsuccessful.

Excitation Transformer Protection – This protection is typically provided by either overcurrent relays on larger generator or fuses on small machines connected on the primary of the excitation transformer (Fig.15). Typically the kVA size of the excitation transformer and its protection is provided as part of the excitation system package. The time overcurrent protection should be coordinated with the field short time overload capability and field forcing. The short time field capability is specified in terms of DC current as a multiple of field rated current (Fig. 14). The kW component at various field overload levels can be determined by I^2R_f where R_f is the field resistance and I is the field current at various multiples of field rated current. The AC time overcurrent required providing that KW can then be determined at the AC voltage rating of the excitation transformer. Doing so, however, neglects the loss in the bridge circuitry, which can be significant for high ceiling static exciter. The power factor that results can be far from unity with most of the load being vars due to the fact that the bridge circuit is firing with a more delayed angle. The resulting short time current on the AC excitation transformer is a combination of the field current requirements and losses in the bridge circuitry. The excitation system manufacture should be able to provide the relationship of AC current to DC current at various excitation and over excitation levels.

Relay engineers need to be aware of the control and tripping protection that resides within the exciter and its impact on limiting generator overexcitation operation. Traditionally, tripping for excitation system problems such at V/Hz (24), overvoltage (59) and loss of field (40) were done by relays external to the excitation system. This was done to separate protection and control. New digital excitation systems have begun to provide these protection functions within the excitation system control.

A. Testing of Excitation Systems

Operating the generator at its maximum excitation level to ensure that controllers operate to keep the generator within safe limits before protection operates can be periodically tested. Such test may be done not only by bring the generator slowly up to its steady state limit, but also by bringing it rapidly up to the limit so that coordination for short time operation above the steady state limit can be checked. Conducting these tests on a large generator can result in system voltage problems. These tests must be carefully coordinated so that system voltage is maintained within acceptable levels. Reference 13 provides a detail description of testing the exciter OEL, UEL and V/Hz limiter.

B. V/Hz (24) Protection

One of the major functions of V/Hz protection is to serve as a backup in case of the failure of the V/Hz limiter within the excitation control. V/Hz protection is set based on the short time capability of the generator and transformers connected to the generator terminals. 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 [7] provide voltage ranges for generators. Typically the allowable range for continuous operation is between 0.95 and 1.05 pu V/Hz. The manufacturer should be consulted for V/Hz short time capability of a specific generator. The primary concern from an excitation standpoint is the possibility of excessive V/Hz overexciting the generator. When the V/Hz ratios are exceeded, saturation of the iron core of generators and transformers will occur resulting in the breakdown of core inter-lamination insulation due to excessive voltage and eddy current heating.

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 where the voltage regulator is slow in responding. With the AVR control in service, the overexcitation would generally be reduced to safe limits (less than 1.05pu) in a few seconds. The 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 [6] to provide separate V/Hz relaying to protect the generator and any transformers connected to the generator terminals. The setting of these relays is based on the short time V/Hz capability of the generator as shown in Fig.14. In modern application 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 V/Hz limiter 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(s) however, must still protect the generator from damage. This typically is not a problem because the AVR control can adjust generator terminal voltage within seconds.

C. Overexcitation Relay Settings

There are two basic types of V/Hz protection scheme 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 times V/Hz capability of the generator. This scheme can be precisely applied when a V/Hz vs. 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 in order to permit the exciter to operate to reduce voltage before protection action takes place.

D. V/HZ Overexcitation Protection Setting Example

The overexcitation capability limits for the example generator and the connecting transformer are shown in Table 1 and in Fig 14. The main transformer's V/Hz capability has already been adjusted in the table by 19/20 = 0.95 multiplying factor to put its V/Hz capability on the generator's voltage base so the generator's V/Hz capability and the transformer's V/Hz capability points may be plotted together.

The overexcitation transformer limits are define in ANSI/IEEE C57.12 [10] and are measured at the output of the transformer at a power factor of 80%. The output of the generator step-up transformer is at the high voltage terminals of the transformer. If the V/Hz protective relay that is used to protect the generator step up transformer is located at the generator terminals the setting must be compensated for the voltage drop across the leakage reactance of the transformer. This is typically done at the full load rating of the transformer at an 80% power factor. A sample calculation is shown in ANSI/IEEE C37.106 [11]. The values in Table 1 and in Fig.16 have been so compensated. Many new digital transformer relays have V/Hz protective functions within the relay package. The newer practice is to provide the V/Hz step-up transformer protection within the transformer package, and measures V/Hz at the step up transformer high voltage terminals.

The setting calculation example uses two relay elements to provide protection; one inverse time element and a definite time element. The combined protection curve is also shown in Fig.16. The type of curve and time dial should be selected such that the relay characteristic operates before the generator and transformer capability limits are reached.

Table 1 Overexcitation Capability

Main Transformer Capability

Time (min)	**V/Hz (%)**
40	106.4
30	106.9
20	107.4
10	108.4
6	109.3
2	112.1
1	114.3
0.5	118
0.3	123.5

Generator Capability

Time (min)	**V/Hz (%)**
33	110
25	111
20	111.5
15	112.5
10	113.5
5	115.5
2	118
1	120
0.5	122
0.2	125

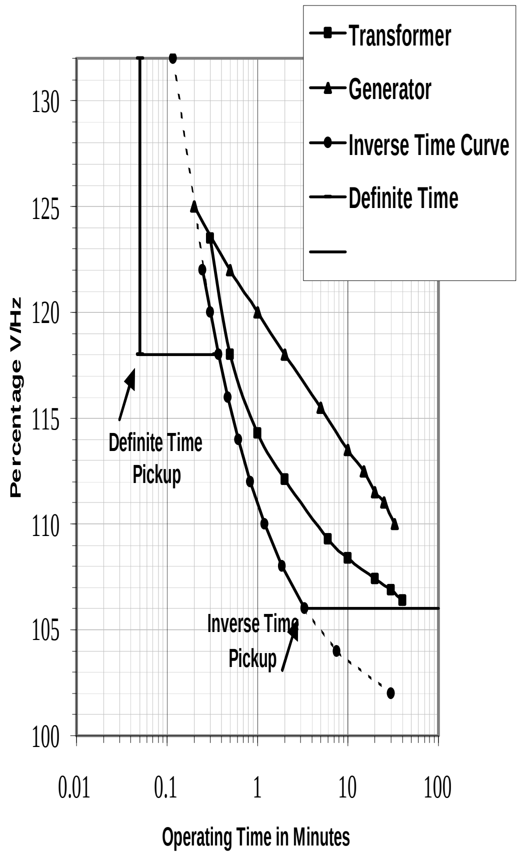

Fig. 16 V/Hz Characteristic Plot

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) and transmission system protection. The techniques, methods and practices to provide this coordination are well established but scattered in various textbooks, papers and relay manufactures literature. This paper provides a single document that can be used by relay engineers to address these coordination issues.

This paper provides practical guidance on proper coordination of generator protection and generator AVR control to enhance security and system stability. The paper uses example calculations as a means of communicating these methods. The paper also addresses the coordination of generator protection with generator full load capability and machine steady state stability. Setting of protective relays is an art as well as a science. The calculations shown in this paper are intended to illustrate typical settings and factors that must be considered in developing generator settings. The Working Group recognizes that other methodologies that affect the same results could also be used. Keeping generators on-line during major system disturbances is a key goal that requires coordination of generator protection with generator control. It is the hope of the Power System Relay Committee Working Group that authored this paper that it will assist the industry in reaching this goal.

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APPENDIX I

Definition of key symbols uses in calculations.

<u>*Steady State Stability Calculations (Section IV):*</u>

X_{TG} = GSU reactance on the generator base.

$X\ \min_{ST1}$ = System reactance with the strongest line (line that contributes the most fault current) out of service. See Fig. 4. Reactance is on the GSU transformer base.
$X\ \min_{SG}$ = System reactance with the strongest line out of service on the generator base.

Loss of Field Relay Coordination (Section V):

$Z1_{Diameter}$ = Loss of Field (LOF) impedance circle diameter setting of Zone 1.
$Z2_{Diameter}$ = LOF impedance circle diameter setting of Zone 2.
$Z1_{Offset}$ = Offset of Zone 1 LOF impedance setting.
$Z2_{Offset}$ = Offset of Zone 2 LOF impedance setting.

Generator Phase Backup (21) Coordination (Section VI):

Zone1 Calculation:

$X_{TG\ \mathrm{sec}}$ = GSU reactance in secondary ohms.
$Z1_{reach}$ = Diameter of Zone 1 impedance setting.
X_{SLG} = Line reactance of the shortest line existing the power plant on generator base.
$X_{L1\mathrm{sec}}$ = Line reactance of the shortest line existing the power plant in secondary ohms.
$Z1_{reach}$ = Zone 1 21relay setting.

Zone 2 Calculations:

Z_{Total} = Total short circuit impedance of a fault at the end of the longest transmission line exiting the power plant.
Z_{LLG1} = Impedance of longest line exiting the power plant on the generator base.
Z_{maxSG1} = System impedance on generator base all lines in service.
I_{Total} = Total fault current for a fault at the end of the longest line exiting the power plant.
I_S = System contribution for a fault at the end of the longest line existing the power plant.
I_G = Generator contribution for a fault at the end of the longest line existing the power plant.
Z_{2_LINE} = Zone 2 relay setting to see the end of the longest line existing the power plant in secondary ohms with 120% margin.
Z_{B_relay} = Generator base ohms

= Rated Gen. Sec. Voltage/Rated Gen Sec. Current
= 69.28V/ 3.95A = 17.56 Ω.

$Z_{\max\ load}$ = Rated load generator impedance in secondary ohms at generator rated power factor.
Z_{2_MTA} = Zone 2 21 setting in secondary ohm at 85^0 to maintain a margin of 150% at rated power factor angle.
Z_{2_MTA2} = Impedance of Generator Capability curve at Max. Torque Angle (MTA) of the Zone 2 relay in secondary ohms with a margin of 90%.