COORDINATING GENERATOR PROTECTION WITH TRANSMISSION PROTECTION AND GENERATOR CONTROL— NERC STANDARDS AND PENDING REQUIREMENTS

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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 key 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. The generator AVR needs to properly control VAr support to rapidly stabilize system voltage during major disturbances. In addition, turbine control should not trip generators for recoverable undervoltage conditions. As a result of the 2003 blackouts, NERC (North Electric Reliability Council) has developed protection standards that generator operators and owner must follow. NERC is also conducting audits to ensure that generator owners and operators are meeting those standards. These standards also address maintenance of the generator protection system.

The record of generator trips (290 units totaling 52,743.9 MW) during the North American disturbance on August 14, 2003, included thirteen types of generator protection relay functions that operated to initiate generator tripping. A list of the protection elements that tripped included: generator system backup protection, over-excitation (volts/hertz), undervoltage, reverse power, loss-of-field, under/overfrequency and inadvertent generator energizing protection. Of the 290 trippings, 96 are unknown trippings by relaying or controls which could not be identified from the monitoring available at these plants. There is no information available that directly addresses which of the 290 trippings were appropriate for the Bulk Electric System (BES) conditions, and which were nuisance trips. In addition to traditional generator protective relay tripping, there were trippings of generator controls for BES voltage dips. Examples are "lean blowout trips" of combustion turbines, Power Load Unbalance (PLU) actuations during system disturbances as well as response of nuclear and other types of generation to system low voltage. The above factors have motivated NERC to become pro-active in addressing the coordination of generator and BPS protection.

II. NERC RELIABILITY STANDARDS

As a result of the 2003 blackout, NERC has developed a series of standards to ensure coordination between generator and transmission line protection. Coordination is defined by IEEE Standard C37.113 (Guide for Protective Relay Applications to Transmission Lines) as:

> "The process of choosing settings or time delay characteristics of protective devices such that operation of the devices will occur in a specified order to minimize customer service interruption and power system isolations due to a power system disturbance."

This definition has wide acceptance within the industry and has been used in NERC documents. In terms of generator–transmission system coordination, it means that generator protection should not trip for faults on the transmission system unless the transmission system primary and backup protection has failed—requiring generator tripping to clear the fault. In addition, generator protection and control should not trip for stable transient voltage reductions or power swings. NERC Standard PRC-001 entitled: System Protection Coordination [1] states the following specific requirements:

<u>PRC-001-1 System Protection Coordination [1]</u>

R1. A <u>Generator Operator</u> or Transmission Operator shall coordinate new protective systems and changes as follows.

R3.1. Each <u>Generator Operator</u> shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

R5. A <u>Generator Operator</u> or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the protection systems of others:

R5.1. Each <u>Generator Operator</u> shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems.

PRC-004-1 Analysis and Mitigation of Transmission and Generation Protection System Misoperations.

R2. The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future misoperations of a similar nature according to the Regional Reliability Organization's procedures.

There are other NERC standards [2] that address generator controls—specifically AVR controls. These are addressed in the proposed compliance template NERC planning standards.

Compliance Template NERC Planning Standards (Proposed)

S4. Generator voltage regulator controls and limit functions (such as over and under excitation and volts/hertz limiters) shall coordinate with the generator's short duration capabilities and protective relays

The above NERC requirement clearly states that generation and transmission protection must be coordinated and that the AVR control must coordinate with generator protective relays. If these systems are not coordinated, it subjects the generator operator to a violation and possible fine if the miscoordination results in or impacts a major system disturbance.

III. NERC AUDITS

NERC audits are conducted by the Regional Reliability Organization (RRO). These regional reliability organizations are NERC sub-groups that monitor their respective regions within North America. The areas of each of these regional organizations is shown in Figure 1.

There are two types of NERC audits:

General Audits: These audits are conducted by the RROs to assess compliance with NERC reliability standards. They involve assessing utility/generator owner procedures and practices. Items such as relay setting procedures and communication of relay settings to field personnel are audited. The maintenance program for the protection and control system are also audited. These audits require documentation of procedures and evidence that the procedures were carried out within the specified timeframe. Failure to meet these requirements will result in a citation requiring the audited entity to correct the violation within a specified time period.

CVI (Compliance Violation Investigation) Audits: These audits are done after a major system event or blackout where there is reason be believe that there may be a failure to comply with NERC standards. A detailed NERC Event Analysis Report is developed which provides an analysis of the event. Information such as relay targets, sequence of events monitors, operator reports and oscillographs provide the base information used to analysis the event. If there is not enough monitoring to determine what happened, the utility/generator owner can be cited for a violation of PRC-018-1 which establishes minimum system monitoring requirements. The NERC event report generally recommends corrective action measure, to avoid re-occurrence of the event.

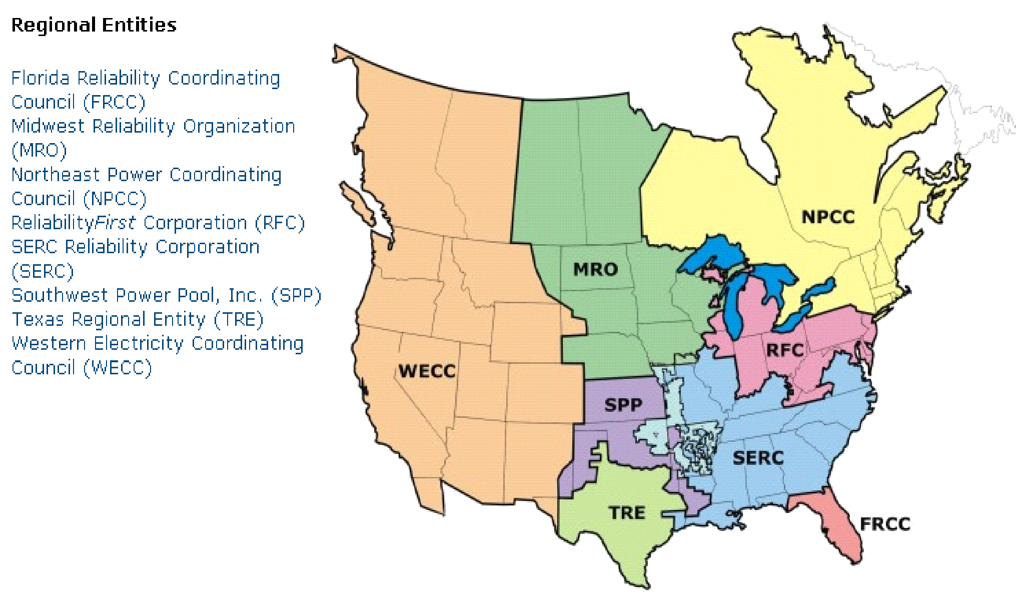


Figure 1. NERC Regional Reliability Organizations (RROs)

The CVI team is formed—comprised of RRO, NERC and FERC members—and begins the process of determining if there is a possible violation of NERC standards. This process requires the audited entity to respond to requests for specific information to determine if they are in compliance with NERC standards. If there is a determination by the audit team that there is a possible violation of NERC standards, a PAV (Possible Audit Violation) is developed which cite the standard that is alleged to have been violated and the specific reasons why the audit team believes the standard was violated. The PAVs are turned over to the NERC assessment committee, which sets a dollar value of the proposed fine. The utility/generator owner can appeal the findings – if unsuccessful, the fine must be paid.

IV. COORDINATION OF GENERATOR AND TRANSMISSION SYSTEM PROTECTION

Figure 2 shows a typical unit-connected generator with the IEEE recommended complement of relays as well as which relay functions initiated tripping during the August 14, 2003 blackout [3, 4].

Six relay functions in Figure 2 accounted for the vast majority of trippings. The setting criteria for these relays are discussed below:

System Backup Protection (21 & 51V) The Device 21 relay measures impedance derived from the quotient of generator terminal voltage divided by generator stator current. This relay function provides backup protection for system faults that have not been cleared by transmission system protective relays. The Device 51V, Voltage-Controlled or Voltage-Restrained Overcurrent, Protections, is another method of providing backup for system faults, and it is never appropriate to enable both Device 51V and Device 21.

Voltage-Controlled and Voltage-Restrained Overcurrent Protections measure generator terminal voltage and generator stator current. Its function is to provide backup protection for system faults when the power system to which the generator is connected is protected by time- protections. The preferred device for protection of generators that are interconnected to the bulk power transmission system is the 21 device because the protection on the transmission system is typically comprised of 21 relays. The coordination between these relays can be most effectively done because these relays have the same operating characteristics–i.e., they both measure impedance. The 51V backup relay is designed for application where the system to which the generator is connected is protected by time overcurrent relaying. Because of the cost differences in electro-mechanical technology, the 51V relays were used to provide backup protection in place of the more expensive 21 relays which contributed to the number of misoperations that occurred during the 2003 East Coast blackout.

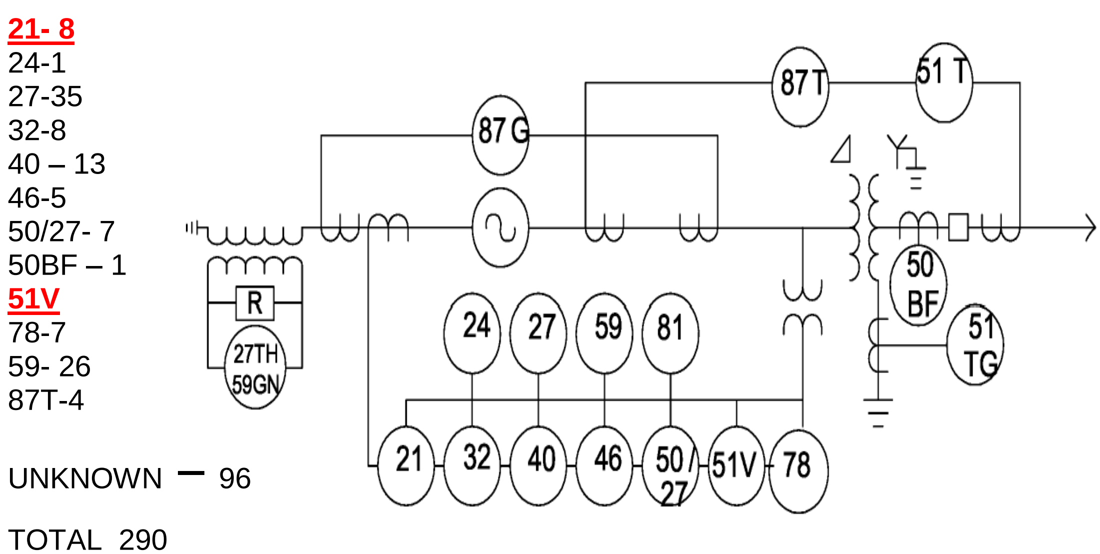


Figure 2. Breakdown by Relay Function of East Coast 2003 Generator Trippings [5]

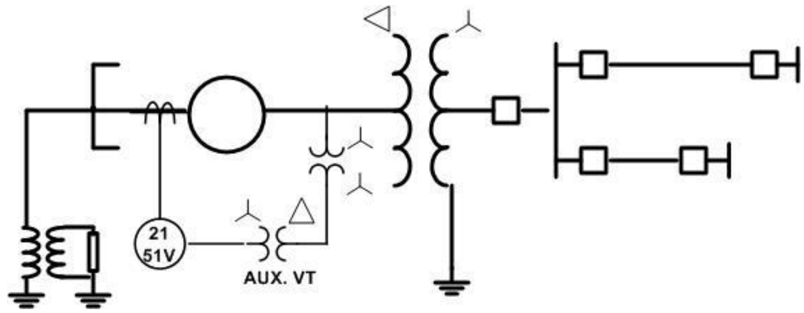


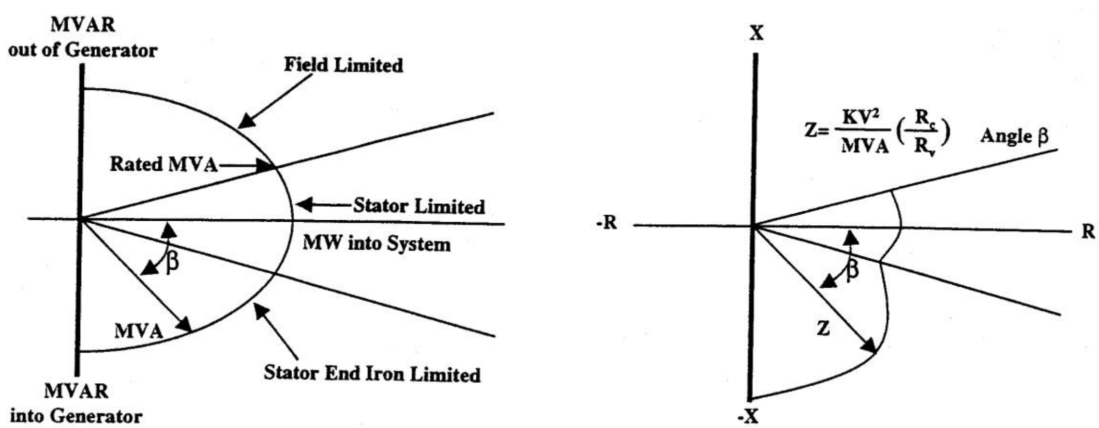
Figure 3. Connection of 21 and 51V System Backup Protection

Figure 3 shows a one-line connection diagram for these relays. These relays are set to respond to faults on the transmission system and their tripping is delayed to allow the transmission system protection to operate first. The degree to which the relays can be set to respond to transmission system faults is almost always limited due to loadablility considerations. The generator steady-state load capability is described by the generator capability curve that plots the MW–MVAR capability. As discussed above, the 21 relay operates by measuring impedance. The generator capability must be plotted on the relay operating impedance plot to determine what the loadability is in relationship to the relay settings. Figure 4 describes how to do 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.

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 impedance value of the faulted line to appear further away and requires a larger impedance 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 backup relay to respond to faults at the end of the longest lines is mitigated since local backup has been provided on the transmission system.



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

Figure 4. Transformation for Mw-MVAr to R-X Impedance Plot [6]

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 second 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 degrees)

The capability curve for the generator and settings are plotted on the R-X impedance diagram as shown in Figure 5. 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 and be set so that it does not operate on stable power swings.

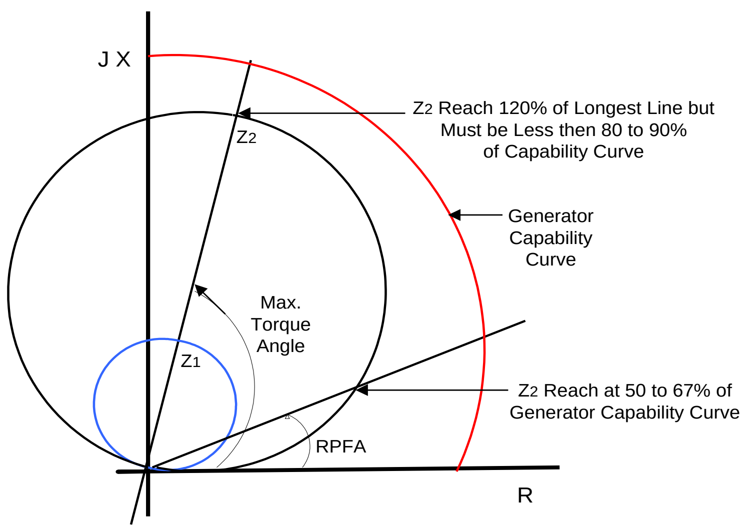


Figure 5. Generator Phase Distance Backup Protection Settings

Undervoltage Protection (27): Undervoltage (Device 27) tripping of generators was the single biggest identifiable cause of generator tripping during the 2003 blackout. The device 27 measures generator terminal voltage. IEEE Standard C37.102 – IEEE Guide for AC Generator Protection [7]-- does not recommend use of the 27 function for tripping, but only to alarm to alert operators to take necessary actions. Undervoltage alarms as experienced by hydro, fossil, combustion and nuclear units are an indicator of possible abnormal operating conditions such as excitation problems and thermal issues within the unit. Other alarms from RTDs and hydrogen pressure are better indicators of thermal concerns.

Manufacturers recommend operator action up to and including reduction in unit output rather than a unit trip. Generators are usually designed to operate continuously at a minimum voltage of 95% of its rated voltage, while delivering rated power at rated frequency. Operating a generator with terminal voltage lower than 95% of its rated voltage may result in undesirable effects such as reduction in stability limit, import of excessive reactive power from the grid to which it is connected, and malfunctioning of voltage sensitive devices and equipment. Low generator voltage can affect the plant auxiliary system supplied from the generator auxiliary transformer. Auxiliary systems at steam plants contain a large number of motors, which are constant KVA devices that can be overloaded due to low voltage. The lower their operating voltage, the more current the motor draws. Thus, plant auxiliary system motors can and have tripped via their thermal protection for low generator terminal voltage. Generator undervoltage relays should not be used to protect these motors. The thermal protection on the motors should be the protection element that protects these motors from overload.

At nuclear plants, the voltage on the I-E busses is typically monitored by undervoltage relays. If 1-E voltage drops to a point where the plant cannot be safely shut down, the diesels are started and the I-E loads transfers to the diesels. The plant then must be shut down if system voltage does not return to normal. The nuclear plant should provide the transmission system operator the level of the1-E separation voltage so that planning studies can recognize the possible tripping of the nuclear plant due to low system voltage.

Inadvertent Energizing Generator Protection (27/50): Inadvertent or accidental energizing of off-line generators has occurred often enough to warrant installation of dedicated protection to detect this condition. Operating errors, breaker head flashovers, control circuit malfunctions, or a combination of these causes has resulted in generators being accidentally energized while off-line.

The problem is particularly prevalent on large generators that are commonly connected through a disconnect switch to either a ring bus or breaker-and-a-half bus configuration. Figure 6 illustrates this type of bus configuration.

These bus configurations allow the high voltage generator breakers to be returned to service as bus breakers, to close a ring bus or breaker-and-a-half bay when the machine is off-line. The generator, under this condition, is isolated from the power system through only the high-voltage disconnect switch. While interlocks are commonly used to prevent accidental closure of this disconnect switch, a number of generators have been damaged or completely destroyed when interlocks were inadvertently bypassed or failed and the switch accidentally closed. When a generator on turning gear is energized from the power system (three-phase source), it will accelerate like an induction motor. The generator terminal voltage and the current are a function of the generator, transformer, and system impedances. Depending on the system, this current may be as high as 3 pu to 4 pu and as low as 1 pu to 2 pu of the machine rating. While the machine is accelerating, high currents induced into the rotor may cause significant damage in only a matter of seconds. If the generator is accidentally back-fed from the station auxiliary transformer, the current may be as low as 0.1 pu to 0.2 pu. While this is of concern and has occurred, there have not been reports of extensive generator damage from this type of energizing; however, auxiliary transformers have failed.

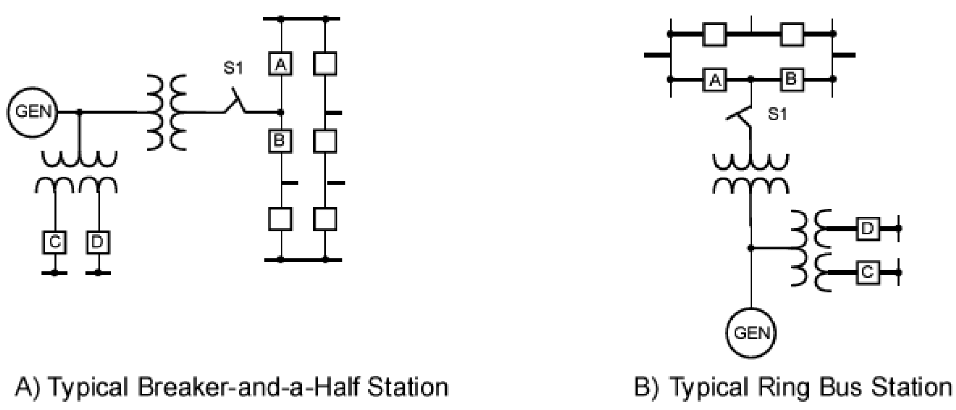


Figure 6. One-Line Diagrams for High-Voltage Generating Stations

The most commonly installed scheme to provide protection for inadvertent energizing protection is a voltage controlled overcurrent scheme shown in Figure 7.

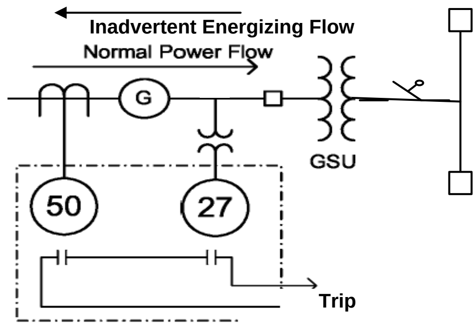


Figure 7. Inadvertent Energizing Protection Scheme

When the unit is off-line, an undervoltage relay (27) operates to arm an instantaneous overcurrent relay (50) to provide rapid detection of an inadvertent energizing event. The inadvertent energizing protection must be in-service when the generator is out-of-service. The inadvertent energizing protection is removed from service when the unit is synchronized to the system by the undervoltage relay. The automatic enabling and disabling of the scheme occurs through settable timers not shown in Figure 7. During the August 14, 2003 event, seven units using these schemes operated on in-service generators due to depressed voltage and unnecessarily removed those units from the system. It is believed that these units had the undervoltage supervision set above the recommended set point of less than 50% of nominal voltage.

Loss of Field Protection (40): 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 from the generator terminals. A two-zone distance relay approach is widely used within the industry to provide high-speed detection. Figure 8 illustrates this approach. An impedance circle diameter equal to the generator synchronous reactance (Xd) and offset downward by half 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 half 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 previously, must be checked for coordination with the generator capability curve, AVR under excitation limiter setting and steady-state stability limit using a calculation method. Figure 8 illustrates this coordination on an R-X impedance diagram. Coordination of loss-of-field must be maintained with generator capability, AVR Under Excitation Limiter (UEL) and steady state stability limit. The generator capability and AVR under excitation limiter information is provided in a MW –MVAr format. The conversion of these limits from MW-MVAr to an impedance R-X plot is required using the method shown in Figure 4. The steady–state stability limit can be conservatively estimated using a graphical method shown in Figure 9. This method assumes a worst case with the AVR out of service — i.e., a fixed generator voltage.

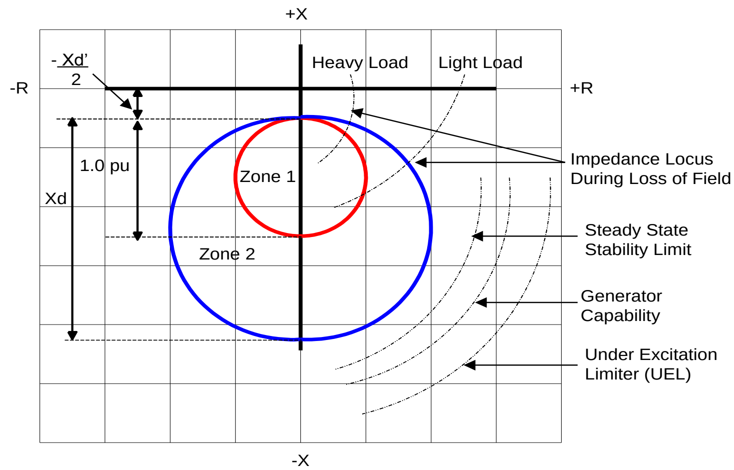


Figure 8. Modern Loss-of-Field Protection Using a Two-Zone Off-Set Mho Method

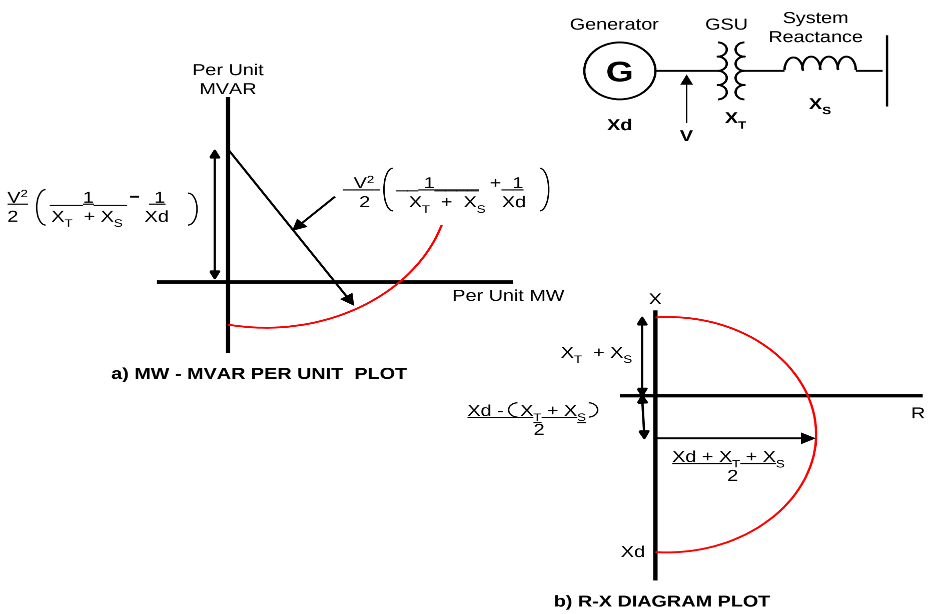


Figure 9. Graphical Method for Steady-State Stability Analysis

Overvoltage Protection (59): The device 59 overvoltage protection uses the measurement of generator terminal voltage. Over-voltage protection is for preventing an insulation break-down from a sustained overvoltage. The generator insulation system is capable of operating at 105% overvoltage continuously. Beyond 105%, sustained overvoltage condition should normally not occur for a generator with a healthy voltage regulator, but it may be caused by the following contingencies: (1) defective AVR operation, (2) manual operation without a voltage regulator, and (3) sudden load loss. Figure 10 shows the connection of the 59 relay on a typical generator.

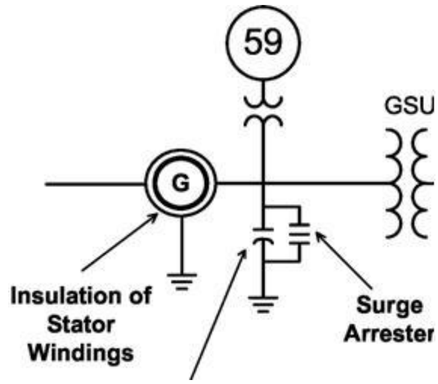


Figure 10. Overvoltage Relay with Surge Devices Shown Connected to the Stator Windings

There are no coordination requirements with the transmission protective relays for system faults given the high voltage setpoint and/or long delay: tens of seconds or longer. Additionally, most system fault conditions would cause a reduction in voltage. The misoperation that occurred during the 2003 blackout appeared to be caused by setting the relay with too short a time delay such that short time system overvoltage conditions during the event triggered the trippings. At a pickup value of 110% nominal voltage a significant time delay of 10 seconds or longer is necessary to ride through extreme system events. Some utilities use a two-step overvoltage approach where a second setpoint is set at a higher voltage with a shorter time.

It is suggested that for creditable contingencies where overvoltage may occur, that all shunt reactors near the generator be placed in service or all capacitor banks near the generator be removed from service prior to the 10 second trip limit on the generator. Overvoltage can also occur when EHV transmission lines exiting the plant are tripped only at the terminal remote from the generating station. These unloaded lines have high shunt capacitance that can raise generator terminal voltage.

Figure 11 provides an example of a voltage regulator response to load rejection where transmission line protection has tripped to cause a sudden loss of generator load. The regulator causes the generator to operate back near nominal voltage in about two seconds, well before any action by the overvoltage protection.

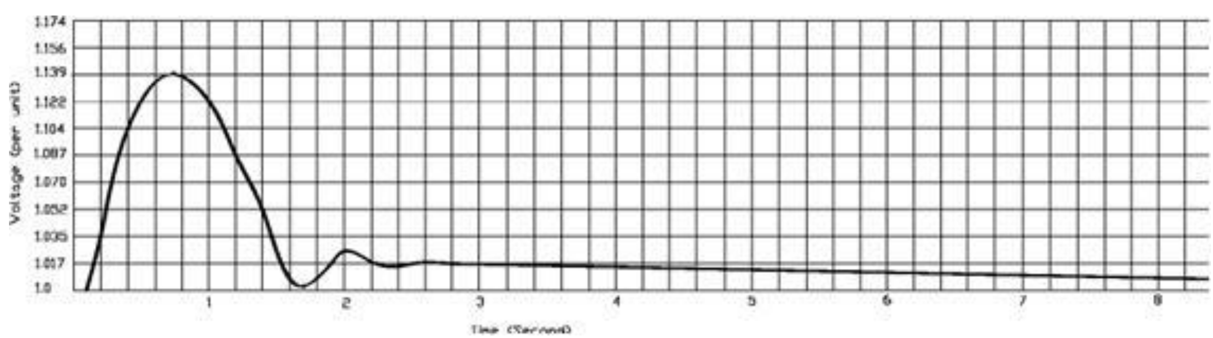


Figure 11. Typical Example of Load Rejection Data for Voltage Regulator Response Time

V. COORDINATION OF GENERATOR PROTECTION WITH GENERATOR CONTROL

In North America, the North America Electric Reliability Council (NERC) requires that system operators have positive assurance 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 that 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 reactance that are verified by test data
- Excitation limiters that are modeled and verified

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

These NERC requirements [4] 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 Figure 12. 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.

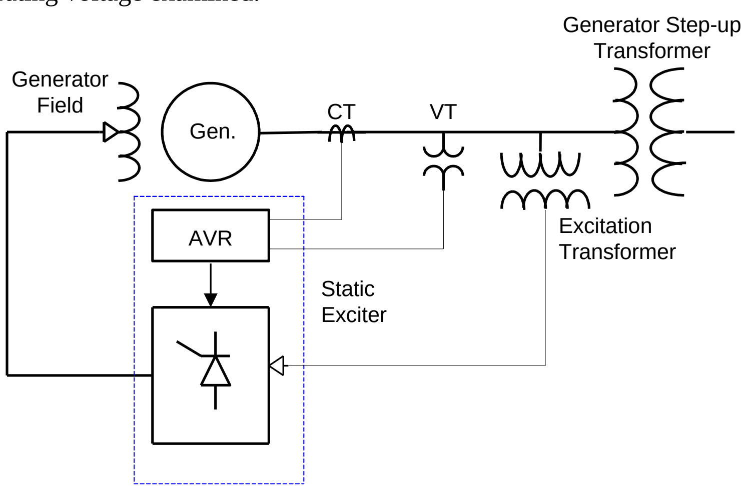


Figure 12. Basic Static Excitation System

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 helps 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. 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 III of this paper.

Using Power System Stabilizers (PSS) to Maintain Stability: As discussed above, a fast-acting AVR is very desirable in helping to 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.

Turbine Controls: During recent blackouts turbine controls have improperly operated due to the voltage dips and frequency transients causef by system short circuits. These voltage dips have resulted in improper operation of Power Load Unbalance (PLU) controls as well as gas turbine “lean blowout” trippings.

Power Load Unbalance (PLU) Trippings: PLUs are applied on large steam generators to avoid over-speed tripping during full load rejection by closing, and then opening, steam values to reduce mechanical energy and avoid over-speed unit tripping. The PLU control scheme automatically initiates closing of intercept and control values within 10 ms. The scheme is triggered by an unbalance of steam and electric power, which exceeds 40%. During system fault conditions, system voltage is reduced. The reduced voltage results in a reduction in the electrical power (MW) output of the generator—unbalancing the electrical and steam power. PLUs have improperly operated for these system conditions. These improper generator trippings have resulted in a Midwest near-blackout and a blackout in New Mexico. The manufacturer states the PLUs are not designed to operate for system fault conditions. A PLU setting restricts operation through a rate of change of power setting, which can discriminate between load rejection and system fault conditions.

There is also a software problem in the GE MKVI turbine control PLU. It has improperly operated for system faults. Once activated, it closes both the control and intercept valves but fails to open the control value which results in a unit trip. GE has issued a technical information letter (TIL 1534-2) to upgrade the scheme to prevent misoperations. NERC may also issue an alert letter to make generator owners aware of the problem.

Gas Turbine “Lean Blowout” Tripping: An operating error resulted in a transmission system 138KV fault in south Florida remaining on the system for 1.7 seconds. During the protracted fault, voltage locally went to near-zero, which effectively reduced the area load and thereby caused area generators to accelerate. Indications are that six combustion turbine (CT) generators within the region that were operating in a lean-burn mode (used for reducing emissions) tripped offline as result of a phenomenon known as "turbine combustor lean blowout." As the CT generators accelerated in response to the frequency excursion, the direct-coupled turbine compressors forced more air into their associated combustion chambers at the same time as the governor speed control function reduced fuel input in response to the increase in speed. This resulted in what is known as a CT "blowout," or loss of flame, causing the units to trip offline.

Generator owners and operators are encouraged by NERC to consult their CT manufacturers to understand and identify the plant’s susceptibility to “turbine combustor lean blowout” as a result of a system over-frequency transient and work with them to identify steps that may mitigate this issue.

VI. 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 engineers to address these coordination issues.

This paper also discusses in detail the important role the generator AVR and turbine control plays during major system disturbances. Since most recent major power system disturbances are the result of voltage collapse, generator protection and turbine control 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.

VII. REFERENCES

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VIII. ABOUT THE AUTHOR

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