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IEEE Guide for AC Generator Protection

IEEE Power Engineering Society

Sponsored by the
Power System Relaying Committee

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Approved 16 November 2006

IEEE-SA Standards Board

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Abstract: A review of the generally accepted forms of relay protection for the synchronous generator and its excitation system is presented. This guide is primarily concerned with protection against faults and abnormal operating conditions for large hydraulic, steam, and combustion turbine generators.

Keywords: ac generator protection, relay protection, synchronous generator

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Introduction

This introduction is not part of IEEE Std C37.102-2006, IEEE Guide for AC Generator Protection.

IEEE Std C37.102 was initially published in 1987. It was subsequently revised in 1995 and reaffirmed in 2002. The guide is designed for the protection of typical steam, hydraulic, and combustion turbine generators (CTGs). Schemes that are judged to be good alternative practice for generator protection are included. New schemes that have gained acceptance and usage have been added to the guide.

In this revision of IEEE Std C37.102-1995, several areas were improved. Among the most notable are the following additions:

- A new clause (Clause 6) on multifunction generator protection systems (MGPS)
- A new annex (Annex A) on sample calculations for setting of generator protection functions

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Contents

IEEE Guide for AC Generator Protection

1. Scope

This application guide for the relay protection of synchronous generators presents a review of the generally accepted forms of protection for the synchronous generator and its excitation system. It summarizes the use of relays and devices and serves as a guide for the selection of equipment to obtain adequate protection. The guide is primarily concerned with protection against faults and abnormal operating conditions for large hydraulic, steam, and combustion turbine generators. Basing generator protection on machine size is difficult because the desired protection may be determined more by the importance of the generator to the power system than by the size of the generator.

The recommendations made pertain to typical synchronous generator installations. However, sufficient background information relating to protection requirements, applications, and setting philosophy is given to enable the reader to evaluate the need, to select, and to apply suitable protection for most situations.

The protective functions discussed in this guide may be implemented with a multifunction microprocessor based protection system (digital system). The protection philosophy, practices, and limits are essentially identical to those of the implementation using discrete component relays. The algorithms used to perform some of the protection functions may be different, but should produce equal or better protection. However, the performance and capability may be superior using the digital systems such as improved frequency response (bandwidth) and thresholds (pickup settings). Other additional features may be available from these digital systems that enhance the functionality.

This guide does not purport to detail the protective requirements of all generators in every situation. For example, standby and emergency-use generators are specifically excluded.

1.1 Description of the guide

Clause 3 presents a brief description of typical generator design and connections, generator grounding practices, excitation systems design, and generating station arrangements. The intent of this clause is to present information that affects the protection arrangement and selection of protective relays.

A discussion of auxiliary system transfer and the possible negative impacts of misoperation and faults on these systems are beyond the scope of this guide.

The methods employed for grounding and fusing the secondary circuits of voltage transformers (VTs) and the methods for grounding current transformer (CT) secondary circuits are not generally the same for all installations. CT and VT secondary circuits should be grounded in accordance with IEEE Std C57.13.3™.[1]

Clause 4 briefly describes the damaging effects of faults and abnormal operating conditions and the type of devices and their settings commonly used to detect these conditions. A clear understanding of the effects of abnormalities on generators will assist the reader in evaluating the need for and the means of obtaining adequate generator protection in any specific situation.

Clause 5 presents a discussion of other forms of protection and factors that may be considered in the generator zone.

Clause 6 describes multifunction generator protection systems (MGPS) and presents an application on a typical generating unit and includes information on testing of MGPS.

Clause 7 presents detailed diagrams that are classified according to the method by which the generator is connected to the system. These diagrams show the combination of relays (and their control function) often applied for generator and excitation system protection in accordance with good engineering practices. These diagrams also consider the protective devices on other equipment in or adjacent to the generating station that are connected to trip or shut down the generator.

Annex A describes sample calculations for settings of generator protection functions.

2. Normative references

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

IEC 60034-1, Rotating Electrical Machines—Part 1: Rating and Performance.[2]

IEC 60034-3, Rotating Electrical Machines—Part 3: Specific Requirements for Cylindrical Rotor Synchronous Machines.

IEEE Std 67™, IEEE Guide for Operation and Maintenance of Turbine Generators.[3, 4]

IEEE Std 142™, IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems *(IEEE Green Book).*

IEEE Std 421.1™, IEEE Standard Definitions for Excitation Systems for Synchronous Machines.

IEEE Std 502™, IEEE Guide for Protection, Interlocking, and Control of Fossil-Fueled Unit-Connected Steam Stations.

IEEE Std C37.91™, IEEE Guide for Protective Relay Applications to Power Transformers.

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[1] Information on references can be found in Clause 2.

[2] IEC publications are available from the Sales Department of the International Electrotechnical Commission, Case Postale 131, 3, rue de Varembé, CH-1211, Genève 20, Switzerland/Suisse (http://www.iec.ch/). IEC publications are also available in the United States from the Sales Department, American National Standards Institute, 25 West 43rd Street, 4th Floor, New York, NY 10036, USA (http://www.ansi.org/).

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IEEE Std C37.110™, IEEE Guide for the Application of Current Transformers Used for Protective Relaying Purposes.

IEEE Std C50.12™, IEEE Standard for Salient-Pole 50 and 60 Hz Synchronous Generators and Generator/ Motors for Hydraulic Turbine Applications Rated 5 MVA and Above.

IEEE Std C50.13™, IEEE Standard for Cylindrical-Rotor 50 and 60 Hz, Synchronous Generators Rated 10 MVA and Above.

IEEE Std C57.13™, IEEE Standard Requirements for Instrument Transformers.

IEEE Std C57.13.3™, IEEE Guide for Grounding of Instrument Transformer Secondary Circuits and Cases.

IEEE Std C62.92.2™, IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems, Part II—Grounding of Synchronous Generator Systems.

3. Description of generators, excitation systems, and generating station arrangements

3.1 Generator winding design and arrangements

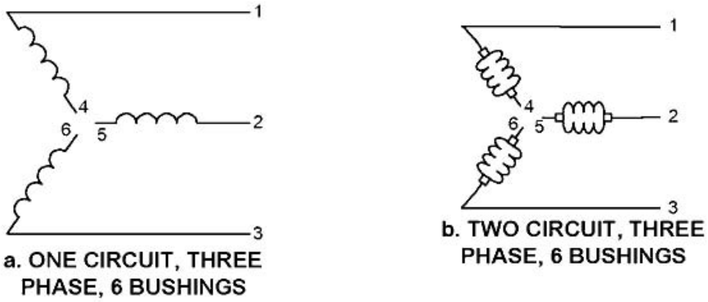
The stator windings of a three-phase synchronous generator consist of a number of single-turn or multi-turn coils that are connected in series to form a single-phase circuit. One of these circuits or several circuits connected in parallel are used to form a complete phase winding. The phase windings are normally connected in wye with the neutral grounded through some external impedance. Delta-connected phase windings are used occasionally but this is not a common connection. Figure 3-1 illustrates the possible winding arrangements and connections.

The winding arrangements shown in parts a) and b) in Figure 3-1 are the configurations most commonly used for all types of generators. When more than one circuit is used per phase as shown in part b) of Figure 3-1, these circuits will be connected in parallel inside the machine and two leads brought out to external connections. In general, up to three current transformers (CTs) may be provided at each end of the phase winding for relaying and instrumentation purposes.

In some hydrogenerator designs, there may be a number of circuits per phase and each circuit may consist of a number of multi-turn coils connected in series. In these machines, the parallel-connected circuits may be formed into two groups that are paralleled, and only two leads are brought out to external connections. There may be an equal or unequal number of circuits in each group. In this design, CTs may be provided in each phase group and in the leads to the external connections.

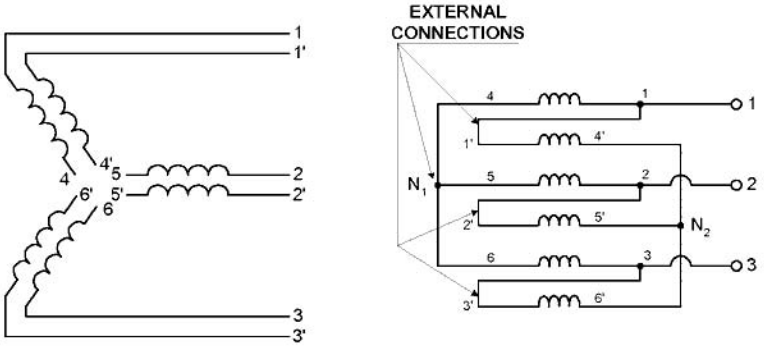
Part c) in Figure 3-1 illustrates the wye-connected double-winding construction sometimes used in large steam turbine generators. Each phase has two separate windings that are connected externally to form two wye connections. The high-voltage terminals of each phase are connected in parallel to form a single three-phase output. Separate wye connections are formed on the neutral end of each winding. These neutrals may be physically at opposite ends of the machine. This arrangement is sometimes referred to as the *double-ended, 12-bushing* machine and is used where the total full-load phase current exceeds the current carrying capability of a single bushing. The bushings at each end of the winding may accommodate three CTs.

In the delta-connected generator, there may be one or more paralleled circuits per phase with two leads brought out to external connections. CTs may be provided inside the delta, at the ends of each winding, or outside the delta, or both.

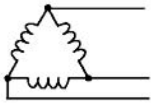


a. ONE CIRCUIT, THREE PHASE, 6 BUSHINGS

b. TWO CIRCUIT, THREE PHASE, 6 BUSHINGS



c. DOUBLE-WINDING, ONE CIRCUIT, THREE PHASE, 12 BUSHINGS



d. DELTA CONNECTION

Figure 3-1—Winding configurations

3.2 Generator grounding

It is common practice to ground all types of generators through some form of external impedance. The purpose of this grounding is to limit the mechanical stresses and fault damage in the machine, to limit transient voltages during faults, and to provide a means for detecting ground faults within the machine. A complete discussion of all grounding and ground protection methods may be found in IEEE Std C62.92.2 and IEEE Std C37.101™-1993 [B62].[5]

The methods most commonly used for generator grounding will be discussed in this guide. They are listed in four broad categories, as follows:

a) High-impedance grounding
b) Low-resistance grounding
c) Reactance grounding
d) Grounding-transformer grounding

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[5] The numbers in brackets correspond to those of the bibliography in Annex B.

Solid grounding of a generator neutral is not generally used since this practice may result in high mechanical stresses and excessive fault damage in the machine. According to IEEE Std C50.13, the maximum stresses that a generator is normally designed to withstand is that associated with the currents of a three-phase fault at the machine terminals. Because of the relatively low zero-sequence impedance inherent in most synchronous generators, a solid phase-to-ground fault at the machine terminals will produce winding currents that are higher than those for a three-phase fault. Therefore, to comply with this standard, generators are grounded in such a manner to limit the maximum phase-to-ground fault current to a magnitude equal to, or less than, the three-phase fault current.

Generators are not often operated ungrounded. While this approach greatly limits the phase-to-ground fault currents, and consequently limits damage to the machine, it may produce high transient overvoltages during faults and also makes the fault location difficult to determine.

The following subclauses provide a very brief description and typical applications of the above grounding methods.

3.2.1 High-impedance grounding

Two methods of high-impedance grounding are in use today: high-resistance grounding and ground fault neutralizer grounding. In both methods, the primary of a distribution transformer is connected between the generator neutral and ground, while the secondary winding rating is 120 V or 240 V. Note that distribution transformers with internal fuses or circuit breakers should not be used, as they could inadvertently be open and the grounding and protection scheme could be inoperative at the time of fault. The two methods differ in their secondary connection as shown in the following subclauses.

3.2.1.1 High-resistance grounding

The high-resistance grounding method utilizes a resistor connected across the secondary of the distribution transformer to limit the maximum ground fault current. The resistor is selected so that for a single-phase-to-ground fault at the generator terminals, the power dissipated in the resistor is equal to, or greater than, three times the total zero-sequence capacitive kVA to ground.

The capacitive kVA to ground includes the generator windings and all other equipment connected to the machine terminals. With this resistor rating, the transient overvoltages during faults will be kept to safe values. For a single-phase-to-ground fault at the machine terminals, the primary fault current will be limited to a value in the range of about 3 A to 25 A. If possible, the ground fault current level should be chosen to coordinate with the primary fuses (when used) of wye-wye-connected VTs with grounded neutrals.

In some cases, the distribution transformer is omitted and a high value of resistance is connected directly between the generator neutral and ground. The resistor size is selected to limit ground fault current to the range of 3 A to 25 A. While this method of grounding is used in some parts of the world, the physical size of the resistors, the required resistor insulation level, and the cost may discourage the use of this method.

3.2.1.2 Ground fault neutralizer grounding (tuned inductive reactor)

The ground fault neutralizer grounding method utilizes a secondary tunable reactor to limit the maximum ground fault current. The ohmic value of this secondary reactor is selected so that, when reflected into the primary circuit, its reactance is equal to one-third of the total zero-sequence capacitive reactance. This capacitive reactance includes the generator and all equipment connected to the generator terminals up to and including the delta-connected windings of the main step-up and station service transformers. This type of grounding limits the single-phase-to-ground fault current to 1 A or less. This low fault current will not sustain an arc or cause damage to the generator stator-iron. Therefore, ground fault neutralizer grounding may detect much higher impedance grounds than is possible with high-resistance ground. Ground fault neutralizer grounding may be used with all unit-system installations where a single generator is connected through its individual wye delta step-up transformer (or transformers) to the system.

Also, ground fault neutralizer grounding may detect much higher impedance grounds than is possible with high-resistance grounding. For example, the calculated maximum detectable fault impedance for a typical nuclear unit of 975 MVA is 3.5 MΩ for ground fault neutralizer grounding. Calculated maximum stator fault current for a typical 975 MVA nuclear unit is 0.45 A. If this generator is grounded through a high-resistance grounding, the maximum fault impedance that may be detected is 67 kΩ (see Gulachenski and Courville [B82]).

If protection from iron burning and greater sensitivity of detecting incipient faults is deemed desirable (for example an existing older generator equipped with high-resistance grounding), retrofitting with ground fault neutralizer grounding may be done by replacing the resistor with a reactor.

Along with these desirable features, there are several that may be considered undesirable:

a) If automatic tripping is used, coordination with generator VT fuses may not be possible. Faults on the secondary wiring may cause ground indications where wye-wye connected generator VTs are used. Coordination may be achieved by various methods, see IEEE Committee Report [B17].
b) High zero-sequence voltages on the generator system are possible if too high a reactor coil constant is selected for the neutralizer.
c) If surge protective equipment is used on the generator, it is selected on the basis of possible higher temporary overvoltages during ground faults. Voltages may be kept to within reasonable limits by selecting a reactor coil constant in a range from 10 to 50 without reducing sensitivity of the fault detection system.

3.2.2 Low-resistance grounding

In this method, a resistor is connected directly between the generator neutral and ground. The resistor is selected to provide sufficient current for selective ground relaying of several machines, feeders, or both. In general, the grounding resistor is selected to limit the generator’s contribution to a single-phase-to-ground fault at its terminals to a value in the range of 200 A up to 150% of rated full-load current. Resistor cost and size usually preclude the use of resistors to limit the current below 200 A or to permit currents above machine rated current.

This method of grounding is generally used where two or more generators are bused at generator voltage and connected to a system through one step-up transformer or where the generator is connected directly to a distribution system having a low-impedance grounding source on the generator bus.

3.2.3 Reactance grounding

This method uses an inductive reactance between the generator neutral and ground. The inductive reactance is selected to produce an X_0/X_1 ratio at the machine terminals in the range of 1 to 10. Common practice is to maintain an effectively grounded system by keeping the X_0/X_1 ratio at 3 or less, see IEEE Std C62.92.2. This method of grounding produces relatively high levels of phase-to-ground fault currents ranging from approximately 25% to 100% of the three-phase fault current.

This grounding method is generally used where the generator is connected directly to a solidly grounded distribution system.

3.2.4 Grounding transformer grounding

This method involves the use of a grounding transformer connected to the machine terminals or to the generator bus. The grounding may be provided by a zigzag transformer or a grounded wye-delta transformer, or by a grounded wye-broken delta transformer with a resistor connected across a corner of the broken delta.

When a zigzag or a grounded wye-delta transformer is used, the effective grounding impedance is selected to provide sufficient current for selective ground relaying.

The grounded wye-broken delta transformer with a resistance in the corner of the broken delta is generally a high-resistance grounded system. The resistance would be selected in the same manner as for the distribution transformer with secondary resistor. This method limits the single-phase-to-ground fault current to a range of 3 A to 25 A primary.

A zigzag or grounded wye-delta transformer may be used as an alternate grounding source when a generator with neutral reactor grounding is connected directly to a distribution system. This approach may also be used where several ungrounded-wye or delta-connected generators are bused at generator voltage.

A grounded wye-broken delta transformer with a resistor across the corner of the broken delta may be used to provide a means for detecting ground faults in ungrounded-wye or delta-connected generators.

3.3 Excitation systems

There are four basic types of excitation systems that are used to control the output of ac machines: the dc generator commutator exciter, the alternator rectifier exciter with stationary rectifier system, the alternator rectifier exciter with rotating rectifier system, and the static excitation system. In terms of response times, excitation systems fall into two categories: rotating and static. Rotating exciters respond slower than static exciters. The speed of response of the excitation system is commonly expressed in terms of the nominal response, which indicates the speed of response during a period of 0.5 s after a sudden 20% reduction in generator terminal voltage. Rotating exciters have nominal response in the range of 0.5 per unit to 1.0 per unit exciter volts per second. Static exciters have nominal response in the range of 2.5 per unit to 3.5 per unit exciter volts per second. The detailed effects of the excitation system nominal response on the fault current characteristics of the generator is beyond the scope of this guide but is well-documented in Higgins, Holly, and Wall [B16]. While a detailed description of these systems is beyond the scope of this standard, their general characteristics will be briefly described in the following subclauses.

3.3.1 System with dc generator-commutator exciter

Figure 3-2 shows a schematic of the primary elements of this system. Not shown on this diagram and the succeeding Figure 3-3, Figure 3-4, Figure 3-5, and Figure 3-6 are the power supplies, such as pilot exciters, the current and potential intelligence inputs to the excitation control, etc., since they are essentially functionally the same for all systems.

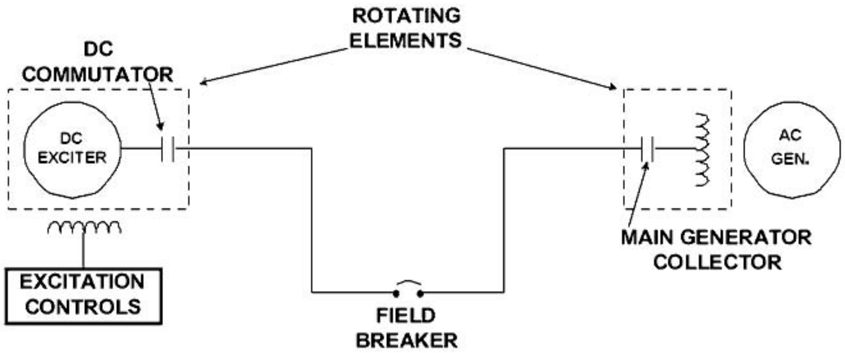


Figure 3-2—System with dc generator commutator exciter

In this system, a dc control signal is fed from the excitation control to the stationary field of the dc exciter. The rotating element of the exciter then supplies a direct current through a field breaker to the field winding of the main ac generator. The rotating armature of the dc exciter is either driven from the same shaft as the rotating main field of the generator or may be on a separate motor-driven shaft. In either case, a dc commutator is required on the exciter and brushes and collector rings are required on the rotating generator field to transmit the main generator field current. This system is used only on the smaller or older machines.

3.3.2 System with alternator rectifier exciter and stationary rectifiers

To eliminate the problems of high-current commutation for medium and large machines, the dc exciter is replaced by an alternator. The system of Figure 3-3 uses an alternator with a rotating dc field winding driven from the shaft of the main ac generator. Current for this field winding is obtained from the excitation controls through brushes and collector rings. The three-phase ac output of the alternator is rectified through a stationary three-phase diode bridge and the direct-current output is fed to the field winding of the generator through brushes and collector rings.

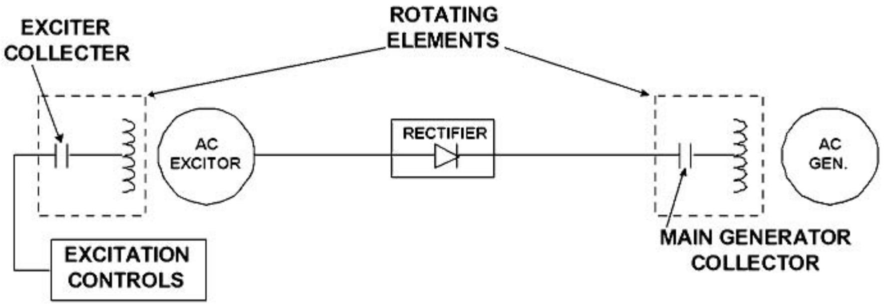


Figure 3-3—System with alternator rectifier exciter and stationary exciter and stationary rectifier

3.3.3 System with alternator rectifier exciter and rotating rectifiers (brushless exciters)

The system of Figure 3-4 again uses an alternator but by mounting the dc field winding on the stator of the exciter and the ac armature winding on the rotor, all brushes and commutators have been eliminated. In this system, the ac armature of the exciter, the rotating three-phase diode bridge rectifier, and the main field of the ac generator are all mounted on the same rotating shaft system. All electrical connections are made along or through the center of this shaft.

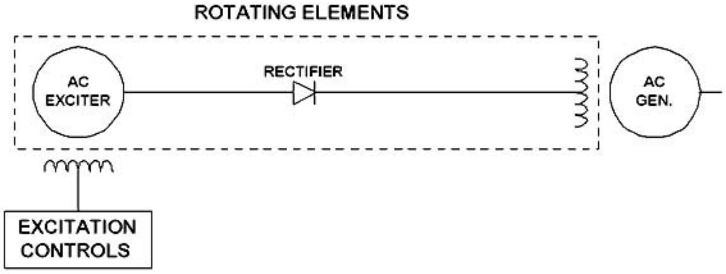


Figure 3-4—System with alternator rectifier exciter and rectifiers (brushless exciters)

3.3.4 System with static exciter

The preceding schemes utilize the energy directly from the prime-mover shaft to obtain the required excitation power. Static excitation systems obtain this power from the electrical output of the generator or the connected system. In Figure 3-5, external power CTs or power VTs (or both) feed rectifiers in the regulating system that, in turn, supply direct current to the main field winding of the generator through brushes and collector rings.

Some systems use only potential transformers as input power, while some use additional CTs to boost the input during fault conditions when the terminal voltage is reduced. During close-in faults, excitation systems using only potential transformers as input power may be unable to sustain fault currents long enough for the protective relaying to operate (see Higgins, Holly, and Wall [B16]).

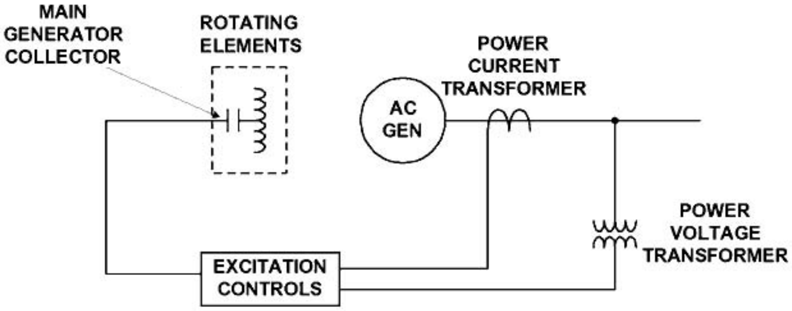


Figure 3-5—System with static exciter

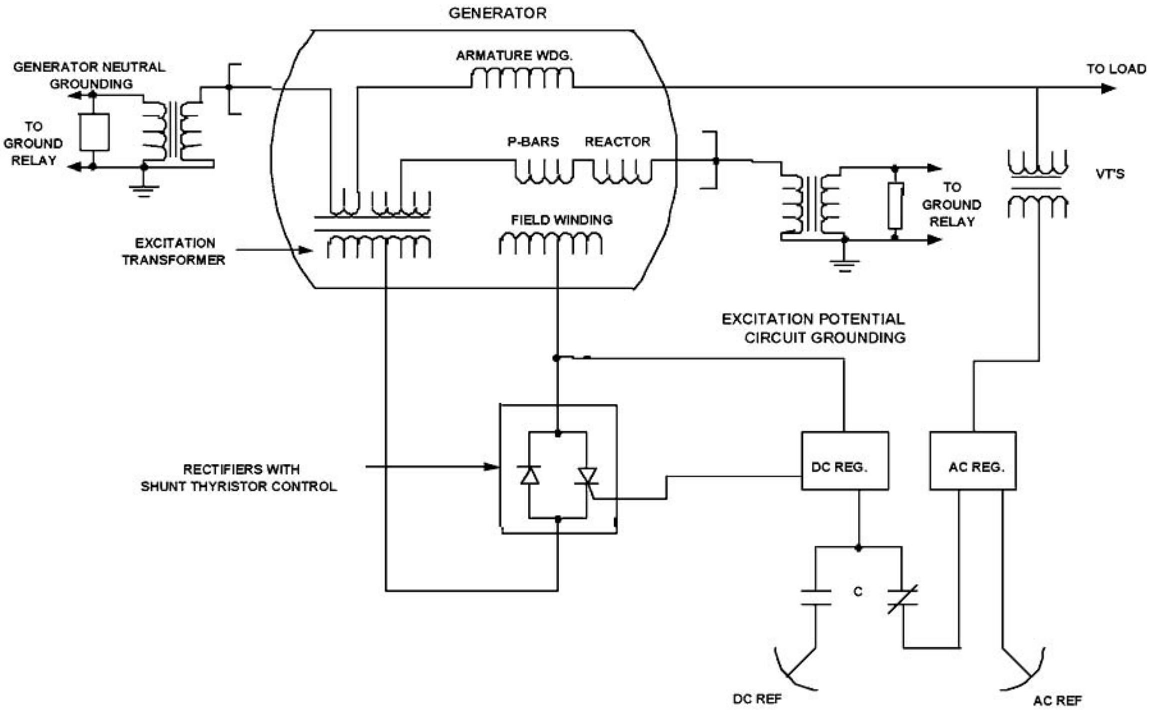


Figure 3-6—Static excitation system with internal supply

In Figure 3-6 the excitation power is provided from a voltage and current source within the main generator. The voltage source is a set of three-phase windings mounted in three generator stator winding slots (P-bars in Figure 3-6). These potential windings are connected to each phase of an ungrounded-wye excitation transformer.

The current source is achieved by passing each of the three stator main winding leads through a window in each phase excitation transformer.

The output windings of the three single-phase excitation transformers are connected in delta to supply the external bridge rectifier circuits. As indicated in Figure 3-6, the potential windings in the stator are connected in wye through linear reactors. The neutral is high-resistance grounded through a distribution transformer, thereby providing a means for detecting possible ground faults in the potential windings and excitation transformer.

3.4 Generating station arrangements

The selection and arrangement of protection for generators is influenced to some degree by the method in which the generators are connected to the system and by the overall generating station arrangement. For purposes of this guide, the following generator connections and station arrangements will be considered:

a) Unit generator-transformer configuration
b) Unit generator-transformer configuration with generator breaker
c) Cross-compound generators
d) Generators sharing a unit transformer
e) Generators connected directly to a distribution system

These configurations represent widely used generating station arrangements.

3.4.1 Unit generator-transformer configuration

In this arrangement, a generator and its transformer (unit transformer) are connected as a unit to the system as shown in Figure 3-7. The generator is usually wye-connected and high-resistance grounded through a distribution transformer. The unit transformer is most commonly a grounded wye-delta connection.

In some large steam turbine generator installations, the generator may be connected to the system through two parallel-connected unit transformers, each transformer having one-half the total generator rating.

There may be one or two unit auxiliaries transformers. These may be two-winding or three-winding transformers, depending upon the size of the generator unit. In most instances the unit auxiliaries transformer(s) is connected delta-wye with the neutral of the wye connected to ground through some impedance.

3.4.2 Unit generator-transformer configuration with generator breakers

This arrangement, illustrated in Figure 3-8, has been used with some large generators. The generator is wye-connected and high-resistance grounded through a distribution transformer. Two half-size grounded wye-delta connected unit transformers are used to connect the generator to the system. As shown in this figure, two unit auxiliaries transformers are used in this arrangement. For small and medium sized generators, a typical configuration is shown in Figure 7-6.

The benefits of this configuration are fast fault removal for generator step-up (GSU) and auxiliary transformer faults and to allow the auxiliary transformer to be used as a start-up source.

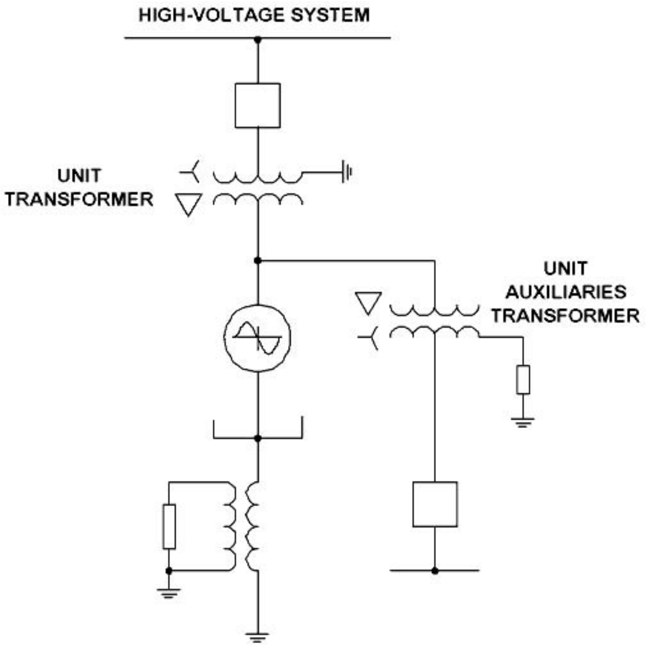


Figure 3-7—Unit generator-transformer configuration

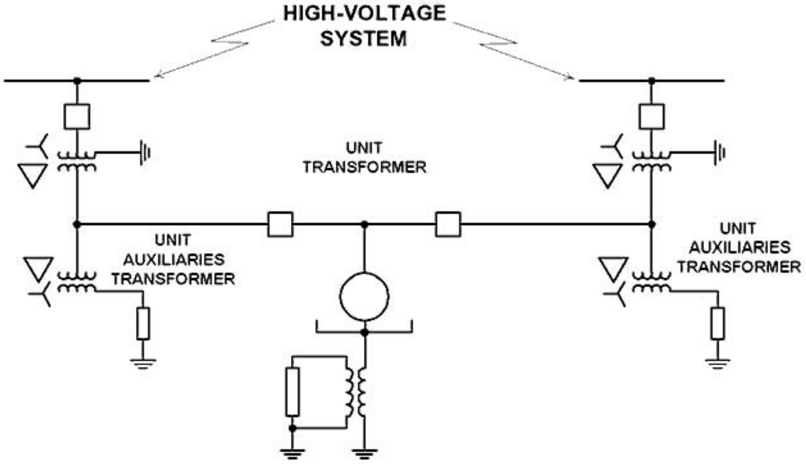


Figure 3-8—Unit generator-transformer configuration with generator breakers

3.4.3 Cross-compound generators

A common method for connecting a cross-compound generator to a system is shown in Figure 3-9. The low-pressure (LP) and the high-pressure (HP) units are bused at generator voltage and connected to the system through a grounded wye-delta unit transformer. Both the low-pressure and high-pressure units are usually wye-connected, and it is recommended practice to ground only one of the neutrals. High-resistance grounding through a distribution transformer is commonly used.

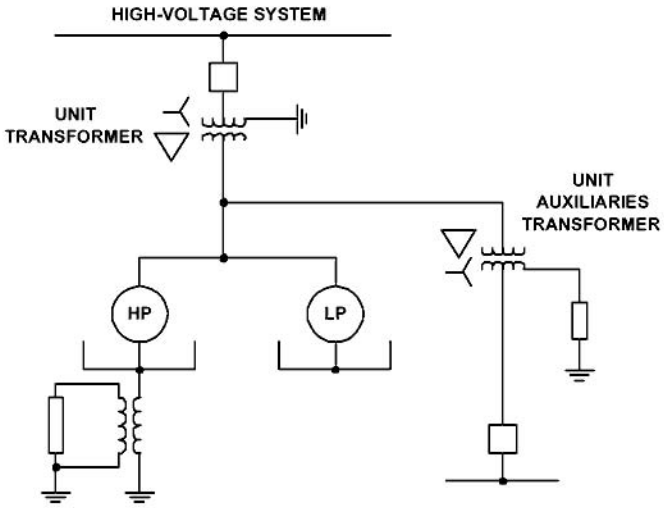


Figure 3-9—Cross-compound generators

3.4.4 Generators sharing a unit transformer

Figure 3-10 illustrates two methods for connecting two or more generators to a system using one step-up transformer. In part A of Figure 3-10, two or more generators are bused at generator voltage and a two-winding grounded wye-delta unit transformer is used to connect the machines to the system. In part B of Figure 3-10, a number of generators are connected to the system through a three-winding grounded wye-delta-delta transformer. Either of these approaches may be used with small hydraulic or combustion turbine generators (CTGs).

In either approach, neutral-resistor grounding of the generators may be used in order to achieve selective ground fault protection for the machines. In some instances, the generators may be high-resistance grounded through a distribution transformer in order to minimize damage due to phase-to-ground faults. However, this grounding method has the disadvantage that it may not provide sufficient current for selective relaying.

Figure 3-11 shows a typical installation where generators are connected directly to a distribution system. If the system is effectively grounded ($X_0/X_1 \leq 3$, $R_0/X_1 \leq 1$), the generator neutral will be grounded with a neutral inductive reactance. As an alternative as noted 3.2.4 a bus-grounding transformer with a neutral reactor may be applied if the generator neutral is ungrounded. If the system is not effectively grounded, the generator neutral or grounding transformer neutral will generally be grounded through a low ohmic value resistor. Where this is used, the feeders off of the bus shall be of the three-wire type (no phase to neutral loads may be permitted)

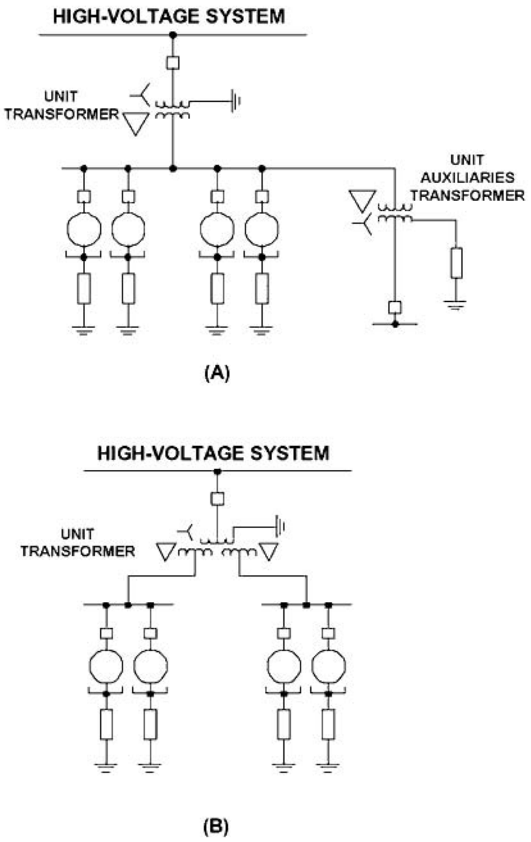


Figure 3-10—Generators sharing a transformer

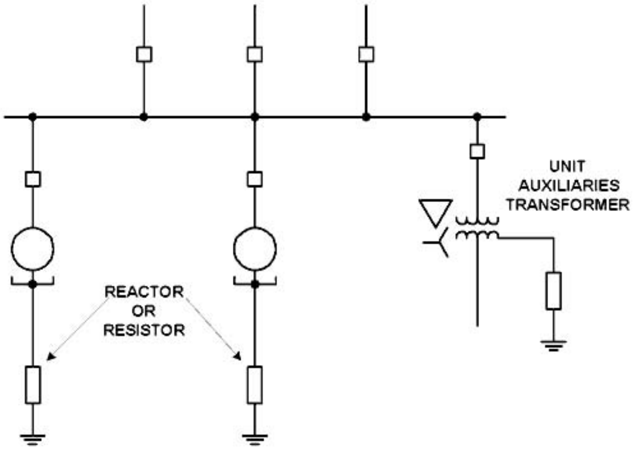


Figure 3-11—Generator connected directly to a distribution system

4. Protection requirements

4.1 Generator stator thermal protection

Thermal protection for the generator stator core and windings may be provided for the following contingencies:

a) Generator overload

b) Failure of cooling systems

c) Localized hot spots caused by core lamination insulation failures or by localized or rapidly developing winding failures

4.1.1 Generator overload

The continuous output capability of a generator is expressed in kilovolt-amperes (kVA) available at the terminals at a specified frequency, voltage, and power factor. For hydrogen-cooled generators, the output rating is usually given at the maximum and several lesser hydrogen pressures. For CTGs, this capability is given at an inlet air temperature in the range of –20° C to 50° C. In general, generators may operate successfully at rated kVA, frequency, and power factor for a voltage variation of 5% above or below rated voltage.

Under emergency conditions, it is permissible to exceed the continuous output capability for a short time. In accordance with IEEE Std C50.13, the armature winding short time thermal capability is given by the following:

Time (seconds)	10	30	60	120
Armature current (percent)	218	150	127	115

where 100% current is the rated current of the machine at maximum hydrogen pressure.

A plot of this short time capability is shown in Figure 4-1. Protective schemes to prevent thermal damage to the stator winding utilize winding temperature (curve drawn using data from IEEE Std C50.13) detectors or relays having time-current characteristics that conform to the short time capability curve.

4.1.1.1 Winding-temperature protection

Most generators are supplied with a number of temperature sensors to monitor the stator windings. These sensors are usually resistance temperature detectors (RTDs) and thermocouples (TCs). As the name implies, the RTD detects temperature by the change in resistance of the sensor. A TC detects temperature by the change in thermoelectric voltage induced at the TC junction.

These sensors are used to continuously monitor the stator winding. In attended generating stations, the sensors may be connected to a data acquisition system for recording or alarm purposes.

In unattended stations, the sensors may be used with a relay to alarm, to initiate corrective action, or to trip the unit if preset temperature limits are exceeded.

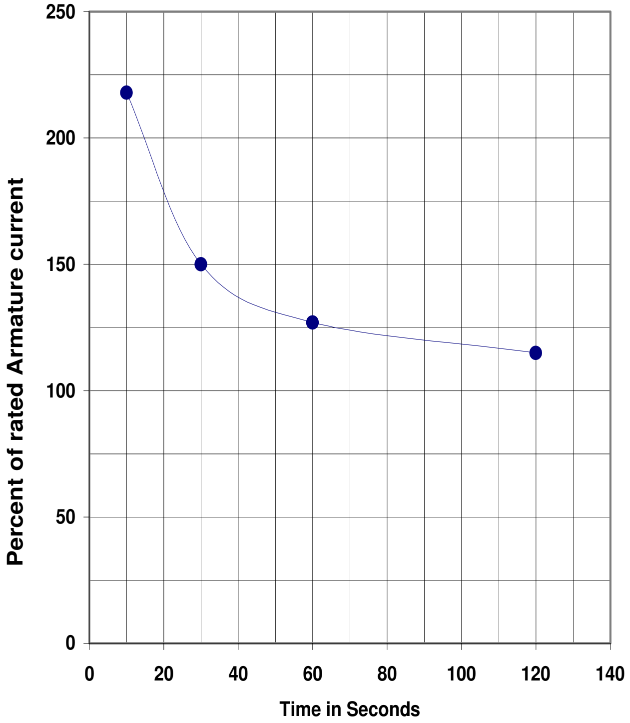


Figure 4-1—Turbine-generator short time thermal capability for balanced three-phase loading

For generators with conventional (indirectly cooled) stator windings, RTDs embedded between the top and bottom bars are used to monitor winding temperatures. For generators with inner-cooled (directly cooled) stator windings, the stator bar coolant discharge temperature is used along with the embedded RTDs (if equipped) to monitor the winding temperature.

The generator manufacturer should be consulted for specific recommendations on the preferred method of monitoring these sensors and temperature limits for alarm and trip purposes.

4.1.1.2 Overcurrent protection

In some instances, generator overload protection may be provided through the use of a torque controlled overcurrent relay that is coordinated with the IEEE C50.13 short time capability curve of Figure 4-1 (curve drawn using data from IEEE Std C50.13). This relay consists of an instantaneous overcurrent (IOC) unit and a time-overcurrent unit having an extremely inverse characteristic. The instantaneous unit is set to pick up at 115% of full-load current and is used to torque control the time-overcurrent unit. The instantaneous unit dropout should be 95% or higher of pickup setting.

The time-overcurrent unit is set to pick up at 75% to 100% of full-load current, and a time setting is chosen so that the relay operating time is 7.0 s at 218% of full-load current. With this approach, the relay is prevented from tripping for overloads below 115% of full-load current and yet provides tripping in a prescribed time for overloads above 115% of full-load current. The overcurrent relay settings should be provided to transmission system protection personnel for coordination purposes.

An overload alarm may be desirable to give the operator an opportunity to reduce load in an orderly manner. This alarm should not give nuisance alarms for external faults and should coordinate with the generator overload protection if this protection is provided.

For air-cooled generators that may operate in a wide range of ambient temperatures, it is necessary to coordinate the IEEE C50.13 thermal capability and the relay setting with the increased capability of the turbine and the generator at reduced ambient temperature. Conversely, it may be difficult to protect the generator for its reduced capability when the ambient temperature is high.

4.1.2 Failure of cooling systems

4.1.2.1 General

Depending upon rating and design, the generator stator core and windings may be cooled by air, oil, hydrogen, or water. In direct-cooled (or so-called conductor-cooled) generators, the coolant is in direct contact with the heat-producing conductors of the stator winding. In indirectly or conventionally cooled generators, the coolant cools the generator by relying on heat transfer through the insulation. For any type of generator, a failure of the cooling system may result in rapid deterioration of the stator core lamination insulation and/or stator winding conductors and insulation.

4.1.2.2 Protection

In general, the generator manufacturer provides all of the necessary protection for the cooling system. This protection is in the form of sensors such as RTDs, TCs, and flow and pressure sensors. These devices are used to monitor the winding temperatures or the coolant temperature, flow, or pressure. They may be connected to alarm, to automatically reduce load to safe levels, or to trip.

For a particular machine, the user should check with the generator manufacturer to ascertain the temperature limits, the protection provided, and the recommended operating procedures for a loss of coolant.

4.1.3 Core hot spots

4.1.3.1 General

Localized hot spots in the stator core may be produced by lamination insulation failure caused by misoperation (such as excessive leading power factor operation or over fluxing), by vibration due to looseness (wear of insulation or fatigue of laminations), by foreign objects left in the machine, by damage to the core during installation or maintenance, or by objects that are normally a part of the machine (such as a nut, wedge, etc.), but become detached from their normal position and move to the core.

The hot spots are the result of high eddy currents, produced from core flux, that find conducting paths across the insulation between laminations. In some designs, stator laminations are electrically shorted together on the outer diameter of the core where it attaches to the stator frame. Any contact between laminations on the inner bore will result in a circuit for eddy currents. The shorting of laminations may cause melting of core steel that may be costly to repair.

4.1.3.2 Protection

A means for detecting hot spots in air-cooled generators is through the use of RTDs and/or TCs embedded in strategic locations. Since it is not possible or practical to cover the entire core and windings with these detectors, this approach may provide only partial detection of hot spots.

On hydrogen-cooled generators, the presence, but not the exact location of local hot spots, may be detected by the use of a generator core (or condition) monitor. The core monitor is an ion particle detector that is connected to a generator in a manner that permits a constant flow of cooling gas to pass through the monitor. Under normal conditions, the gas coolant contains no particles that may be detected by the monitor. However, when overheating occurs, the thermal decomposition of organic material, epoxy paint, core lamination enamel, or other insulating material produces a large number of particles. These particles are of submicron size and are detected by the monitor.

The general location of the hot spot may be determined by laboratory analysis of the particles and through the use of selective coatings on various parts of the machine.

At present, this type of protection is normally supplied on large steam turbine generators and is connected to sound an alarm.

4.2 Field thermal protection

Thermal protection for the generator field may be divided into two categories, as follows:

a) Protection for the main field winding circuit

b) Protection for the main rotor body, wedges, retaining ring, and amortisseur winding

4.2.1 Field winding protection

The field winding may operate continuously at a current equal to or less than that required to produce rated kVA at rated power factor and voltage. For power factors less than rated, the generator output should be reduced to keep the field current within these limits. The capability curves as defined in IEEE Std 67 are determined on this basis.

Under abnormal conditions, such as short circuits and other system disturbances, it is permissible to exceed these limits for a short time. IEEE Std C50.13 lists the short time thermal capability for cylindrical-rotor machines. In this standard, the field winding short time thermal capability is given in terms of permissible field current as a function of time as follows:

Time (seconds)	10	30	60	120
Field current (percent)	209	146	125	113

A plot of this short time capability is shown in Figure 4-2 (curve drawn using data from IEEE Std C50.13). Protection schemes utilize this characteristic to prevent thermal damage to the field winding circuit.

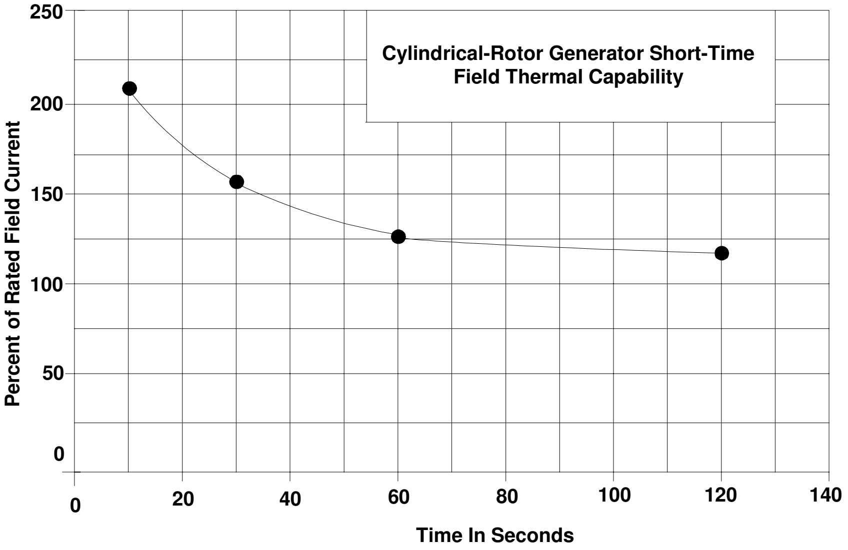


Figure 4-2—Generator field short time thermal capability

4.2.1.1 Thermal protection

Since it is not practical to put temperature sensors directly in the field windings, only indirect monitoring of the field winding temperature is normally possible. For excitation systems employing main field collector rings, the average temperature of the field winding may be approximated by calculating the field resistance using simultaneous field current and voltage readings. This resistance, in conjunction with the known cold resistance, is a measure of the operating temperature.

This method, described in IEEE Std 67, gives only an indication of the average temperature throughout the field winding and not the hot-spot temperature.

Moreover, this method is not applicable with brushless excitation systems where the actual main field current and voltage are not available for measurement.

If a generator is equipped with a core monitor as described in 4.1.3, the monitor may also detect overheating of the field winding.

4.2.1.2 Protection for field overexcitation

Some form of overexcitation protection for the field winding is generally provided utilizing the short time capability curve of Figure 4-2. Several different schemes are available using relays or excitation system control elements, or both.

4.2.1.2.1 Fixed time-delay relaying scheme

One form of field protection utilizes a contact making milliammeter or voltmeter connected in either the main field circuit or in the field of the ac exciter. This device is set to pick up when the field current exceeds its rated full-load value. When an overexcitation condition occurs, the device picks up and performs the following functions:

a) Sound an alarm.
b) Adjust field excitation to a preselected value corresponding to rated full-load level or less.
c) After a fixed time delay, trip the generator regulator or transfer to an alternate control.
d) If overexcitation is not eliminated after some additional short time interval, trip the unit.

This scheme protects the field for overexcitation conditions during system disturbances and for the rare occurrence of a faulty excitation system component. While simple in form, this scheme has the disadvantage that it overprotects the machine, since the fixed time-delay relay is typically set for the maximum possible overexcitation condition that may occur. This means that for less severe overexcitation conditions, tripping occurs at shorter times than is required, and therefore, full advantage of the inverse-time thermal capability of the field winding characteristic is obtained.

4.2.1.2.2 Inverse time-delay relaying scheme

To maximize the probability of machine remaining online after a system disturbance, an excitation system that boosts and operates with a set margin along the inverse time protection characteristic should be considered. This approach utilizes a voltage relay whose characteristic approximately matches the inverse time characteristic of Figure 4-2. This relay may be connected at the terminals of an ac exciter alternator, in the main generator field, or in the field of the ac exciter. When connected to a field circuit, a transducer is used to convert the dc signal to an ac quantity. The relay is normally set so that there is 5% to 10% margin between the relay characteristic and the field capability curve.

This relay, in conjunction with one or more timers, performs the same functions as the preceding scheme. For an overexcitation condition, it will:

a) Sound an alarm.
b) Adjust the field excitation to a preselected value corresponding to rated full-load level or less.
c) After some delay, trip the generator regulator or transfer to an alternate control.
d) If overexcitation is not eliminated, trip the unit.

This scheme provides protection for overexcitation conditions as well as for possible excitation system failures.

4.2.1.2.3 Voltage regulator system

Modern excitation systems may provide field protective functions as well as the regulating function. These systems may have built-in circuitry that duplicates the fixed time and/or the inverse time relaying function. When an overexcitation condition occurs and field current exceeds a safe value for a specified period of time, these protective functions reduce field current to the full-load value or to some other predetermined level. On some excitation systems, if the overexcitation condition persists after an attempt to reduce field current is made, the protective function trips the regulator or transfer to an alternate exciter after a short period of time. If this does not eliminate the problem, the generator may be tripped. In this type of excitation system, the protective function is separate from the excitation function, and therefore, may provide protection when there are failures in the regulating systems or when the regulator is not in the control circuit.

If the protective function is part of the regulating system, the protection is eliminated when the regulator is tripped or is out of service. For this type of system, supplementary relay protection as described in the preceding may be provided.

4.2.2 Rotor body

There are no simple methods for direct thermal protection of the rotor. Various indirect methods are used either to approximate rotor temperatures or to act directly on the quantities that would lead to excessive rotor temperatures. Protection schemes for the rotor are, therefore, directed at the potential causes of thermal distress. For example, negative-sequence currents in the stator, loss of excitation or loss of synchronism may cause excessive rotor temperatures due to circulating currents in various paths of the rotor body. These phenomena and associated protective schemes are covered in 4.5.

4.3 Generator stator fault protection

4.3.1 General consideration

Generator faults are considered to be serious since they may cause severe and costly damage to insulation, windings, and the core; they may also produce severe mechanical torsional shock to shafts and couplings. Moreover, fault currents in a generator do not cease to flow when the generator is tripped from the system and the field disconnected. Fault current may continue to flow for many seconds because of trapped flux within the machine, thereby increasing the amount of fault damage.

As a consequence, for faults in or near the generator that produce high magnitudes of short-circuit currents, some form of high-speed protection is normally used to trip and shut down the machine as quickly as possible in order to minimize damage. Where external impedances are used to limit fault currents to a few amperes, slower forms of protection may be justified. In certain cases, it may be justified to consider the use of rapid de-excitation methods that produce a faster decay of fault currents.

4.3.2 Phase fault protection

Some form of high-speed differential relaying is generally used for phase fault protection of generator stator windings. Differential relaying will detect three-phase faults, phase-to-phase faults, double-phase-to-ground faults, and some single-phase-to-ground faults, depending upon how the generator is grounded.

Differential relaying will not detect turn-to-turn faults in the same phase since there is no difference in the current entering and leaving the phase winding. Where applicable, separate turn fault protection may be provided with the split-phase relaying scheme. This scheme will be discussed subsequently.

Differential relaying will not detect stator ground faults on high-impedance grounded generators. The high impedance normally limits the fault current to levels considerably below the practical sensitivity of the differential relaying.

Three types of high-speed differential relays are used for stator phase fault detection: percentage differential, high-impedance differential, and self-balancing differential.

4.3.2.1 Variable slope percentage differential relay

The variable slope percentage differential relay is a widely used form of differential relaying for generator protection. In this type of relay, the percentage slope characteristic may vary from about 5% at low values of through current up to 50% or more at high values of through current as illustrated in Figure 4-3. This characteristic results in a relay that is very sensitive to internal faults and insensitive to CT error currents during severe external faults.

CTs with identical characteristics should be used in a generator differential scheme. Proper operation of the scheme requires that the CT’s performance during fault conditions is not degraded due to excessive burdens in the circuits. Therefore, care shall be exercised when other relays or devices are used in these current circuits. See IEEE Std C37.110 for more details. CTs of high accuracy class and of low remanence type (i.e., CTs with a gapped core) may be required.

In some cases, proximity effects may affect the accuracy of the CTs, particularly at the neutral ends of generators, where CTs on one phase may be physically close to other phase conductors. In such cases, care is required to ensure that the resulting differential currents are less than the minimum sensitivity of the percentage restrained relay.

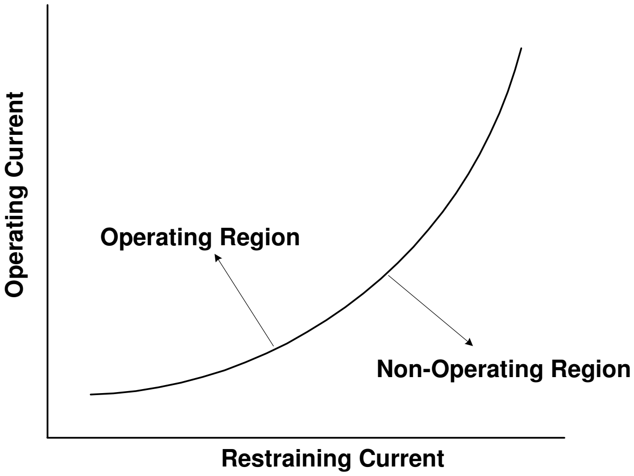


Figure 4-3—Variable slope differential relay

4.3.2.2 High-impedance differential relay

As the name implies, this is a high-impedance relay connected in a differential circuit as shown in Figure 4-4. The relay discriminates between internal and external faults by the voltage that appears across the relay. On external faults, the voltage across the relay will be low, while for internal faults the voltage across the relay is relatively high.

The relay may be set to operate for stator winding three-phase or phase-to-phase fault currents as low as 2% of rated generator current.

The CTs used in this scheme, such as bushing CTs with fully distributed secondary windings, should have identical characteristics and should have negligible leakage reactance.

This scheme has higher sensitivity than the percentage differential relay, and thus may be more susceptible to misoperation caused by proximity effects.

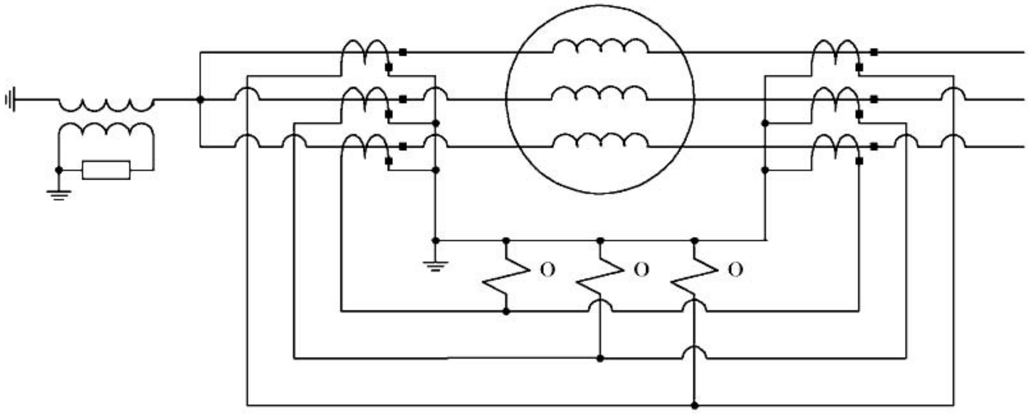


Figure 4-4—High-impedance differential

4.3.2.3 Self-balancing differential scheme

The self-balancing differential scheme has been used for phase and ground faults on small generators with low-resistance neutral grounding. This scheme is illustrated in Figure 4-5. As shown, leads from both ends of the phase winding are placed in the opening of a window-type CT. Any difference between the currents entering and leaving the winding is detected by an IOC relay.

Where applicable, this scheme is capable of providing very sensitive phase and ground fault protection. Since these CTS see a difference current that is normally near zero under nominal system conditions, they are usually not designed to carry continuous load current. This allows the use of CTs with low ANSI accuracy designation and very low CT ratios. The measuring of difference current allows the relay to be set very sensitively to detect very low ground faults within the stator. Use of a low ratio may cause the fault current to be much higher than the 20 times rated current of the CT. Because of this, care should be taken to evaluate the relay burden and the CT saturation characteristics at the required fault current levels to assure accurate pickup of the relay and sufficient secondary current to operate the relay.

The application of phase fault protection to the various machine configurations discussed in 3.1 of this guide is illustrated in Figure 4-6, Figure 4-7, Figure 4-8, Figure 4-9, and Figure 4-10. Figure 4-6 illustrates the differential connections for a six-bushing machine having single-turn coils and one or more circuits per phase. This is the most widely used machine configuration.

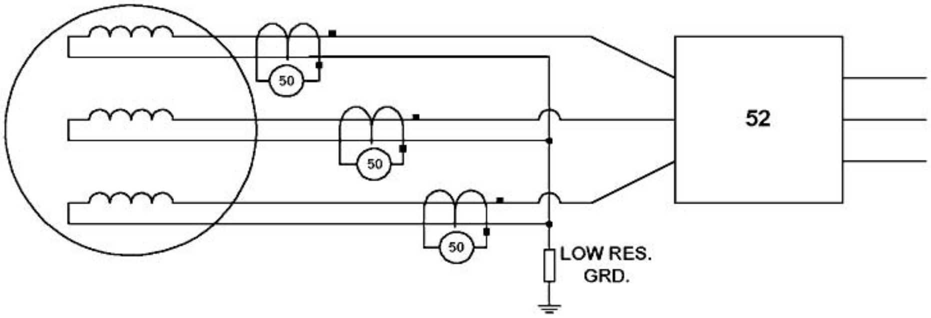


Figure 4-5—Self-balancing protection scheme

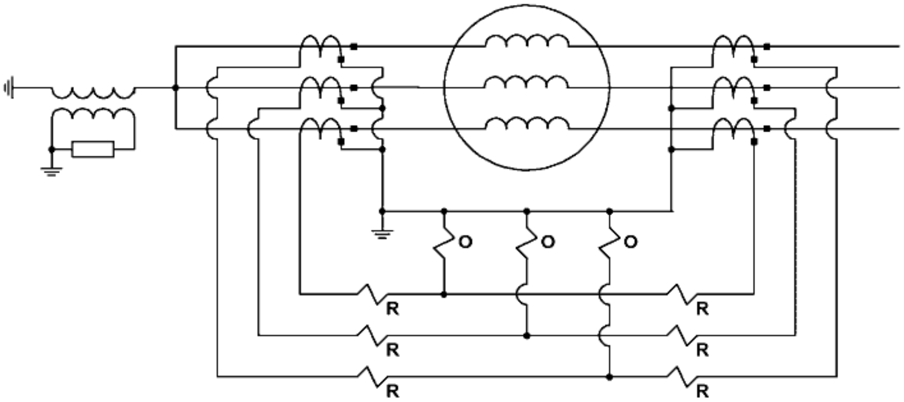


Figure 4-6—Percentage differential relay connection for six-bushing wye-connected generator

4.3.2.4 Application of differential relaying to different machine configurations

Figure 4-7 illustrates the application of split-phase relaying and differential protection on generators having multi-turn coils and two or more circuits per phase. This combination is often used on hydrogenerators. The application of split-phase relaying should be specified in the design of the generator so that the CTs required for this protection may be economically and appropriately engineered into the design.

Another scheme that has been used on this type of generator is shown in Figure 4-8. This arrangement is an attempt to get the benefits of split-phase and differential protection at a saving in CTs and relays. However, this arrangement is not as sensitive as the separate split-phase relaying and differential relaying scheme shown in Figure 4-7. The scheme in Figure 4-8 requires neutral-end CTs having half the turns ratio of the terminal-end CTs.

Figure 4-9 illustrates the protection for a two-winding 12-bushing generator. In this arrangement, separate differential relaying is used to protect each winding. This provides protection for faults between windings and for phase-to-phase and three-phase faults. In general, it is not recommended that the CTs in each winding be paralleled and a single differential relay used. Such an approach would not provide protection for all faults between windings, since for some conditions the fault current would circulate only between the paralleled CTs and would not appear in the relay.

Figure 4-10 shows the typical differential relaying arrangement used for a delta-connected generator.

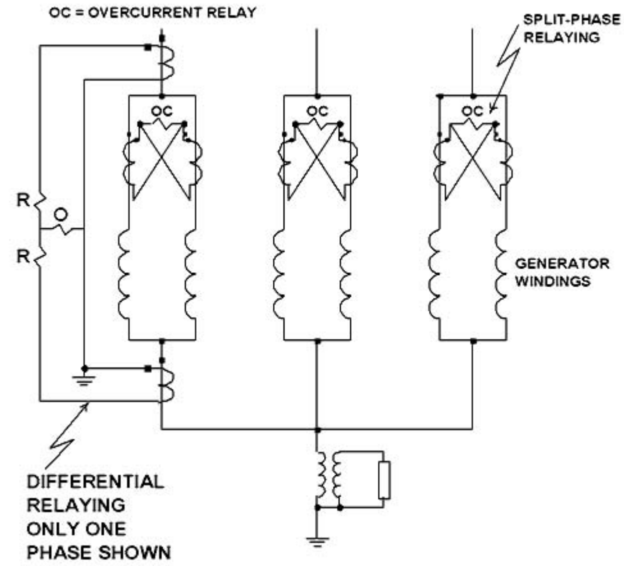


Figure 4-7—Applications of split-phase and differential relaying

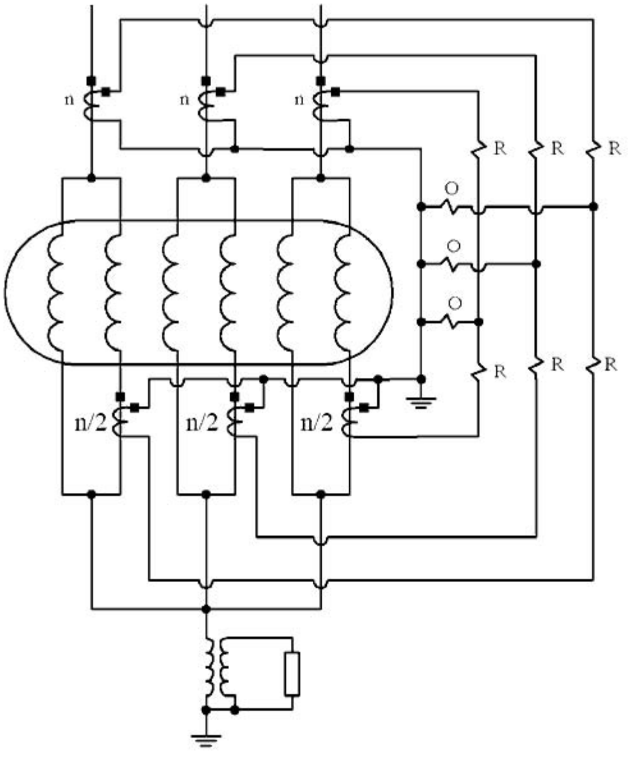


Figure 4-8—Combination split-phase and differential relaying

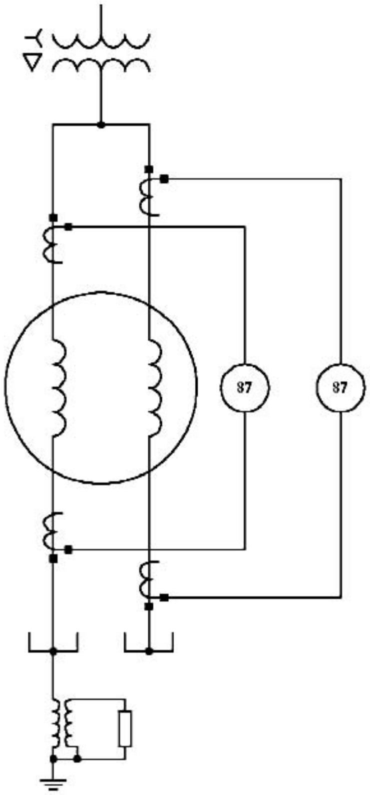


Figure 4-9—Twelve-bushing generator (single phase shown)

4.3.2.5 Turn fault protection

4.3.2.5.1 Split-phase protection

Most turbine generators have single-turn stator windings. If a generator has stator windings with multi-turn coils and with two or more circuits per phase, the split-phase relaying scheme may be used to provide turn fault protection. In this scheme, the circuits in each phase of the stator winding are split into two equal groups and the currents of each group are compared. A difference in these currents indicates an unbalance caused by a single-turn fault. Figure 4-11 illustrates the basic split-phase relaying system using bushing type CTs. The relays used in this scheme usually consist of an IOC relay and a very inverse time-overcurrent relay.

Since there is normally some current unbalance between windings, the time-overcurrent relay is set so that it will not respond to this normal unbalance but will pick up for the unbalance caused by a single-turn fault. Time delay is employed to prevent operation on CT transient error currents that may occur during external faults.

The pickup of the instantaneous unit should be set above the CT error currents that may occur during external faults. The resulting setting offers little turn fault protection. However, it may provide inexpensive backup for multi-turn and phase faults.

The problem of CT error currents with the arrangement of Figure 4-11 may be eliminated by using single window or double window CTs.

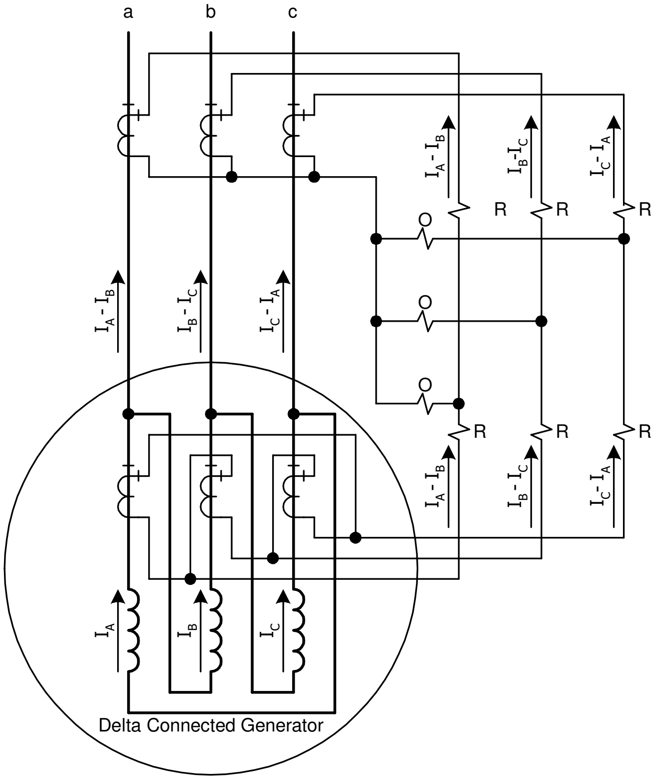


Figure 4-10—Percentage differential relay connection—delta-connected generator

Figure 4-12 illustrates the single window CT arrangement. In this approach, the single window CT eliminates the error currents because of its common core design. The fluxes produced by the primary currents balance each other in the magnetic structure and only the difference current produces an output in the secondary circuit. Therefore, the relays in the secondary more nearly see only the unbalanced current between the circuit groupings.

This permits more sensitive instantaneous relay settings. The single window CT approach is generally restricted to small machines because of physical and insulation problems in arranging the winding leads in the window CT.

The double window CT provides the same advantages of the single window approach but without its physical restrictions. The double window CT approach is shown in Figure 4-13. Again, in this approach only the difference between the primary currents produces an output in the secondary circuit, therefore permitting more sensitive instantaneous relay settings.

If the generator has an odd number of circuits per phase, it still may be possible to provide split-phase protection using separate CTs as shown in Figure 4-11. The currents in the two circuit grouping would not be equal in this case, and therefore, CT ratios would have to be selected to give equal secondary currents during balanced conditions.

In this instance, the single or double window CT approach would not be applicable since the relays would have to be set above a large difference current, making the scheme virtually insensitive to turn faults.

Split-phase protection will detect phase and some ground faults in the stator winding. However, because of the slow operating time of this protection, it is common practice to provide standard high-speed differential protection for each phase and separate ground fault protection.

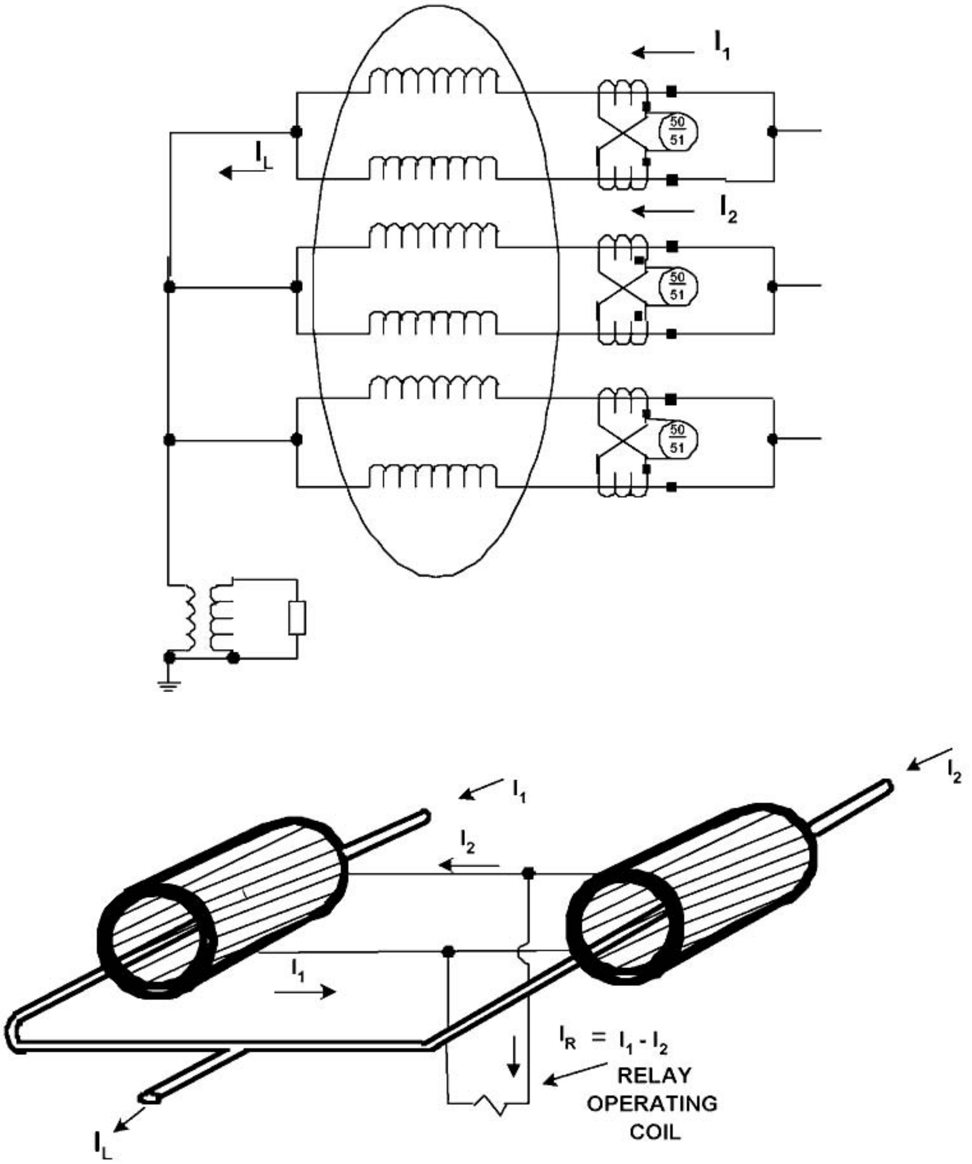


Figure 4-11—Split-phase protection using separate CTs

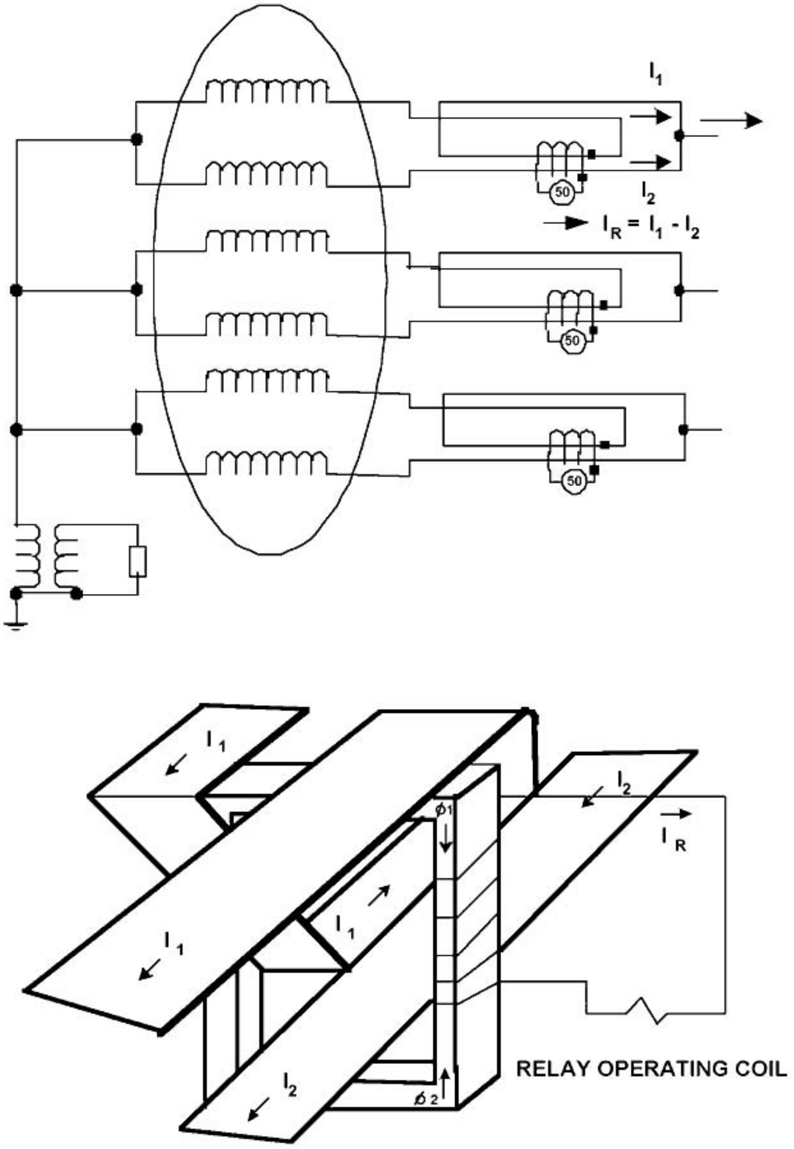


Figure 4-12—Split-phase protection using a single window CT

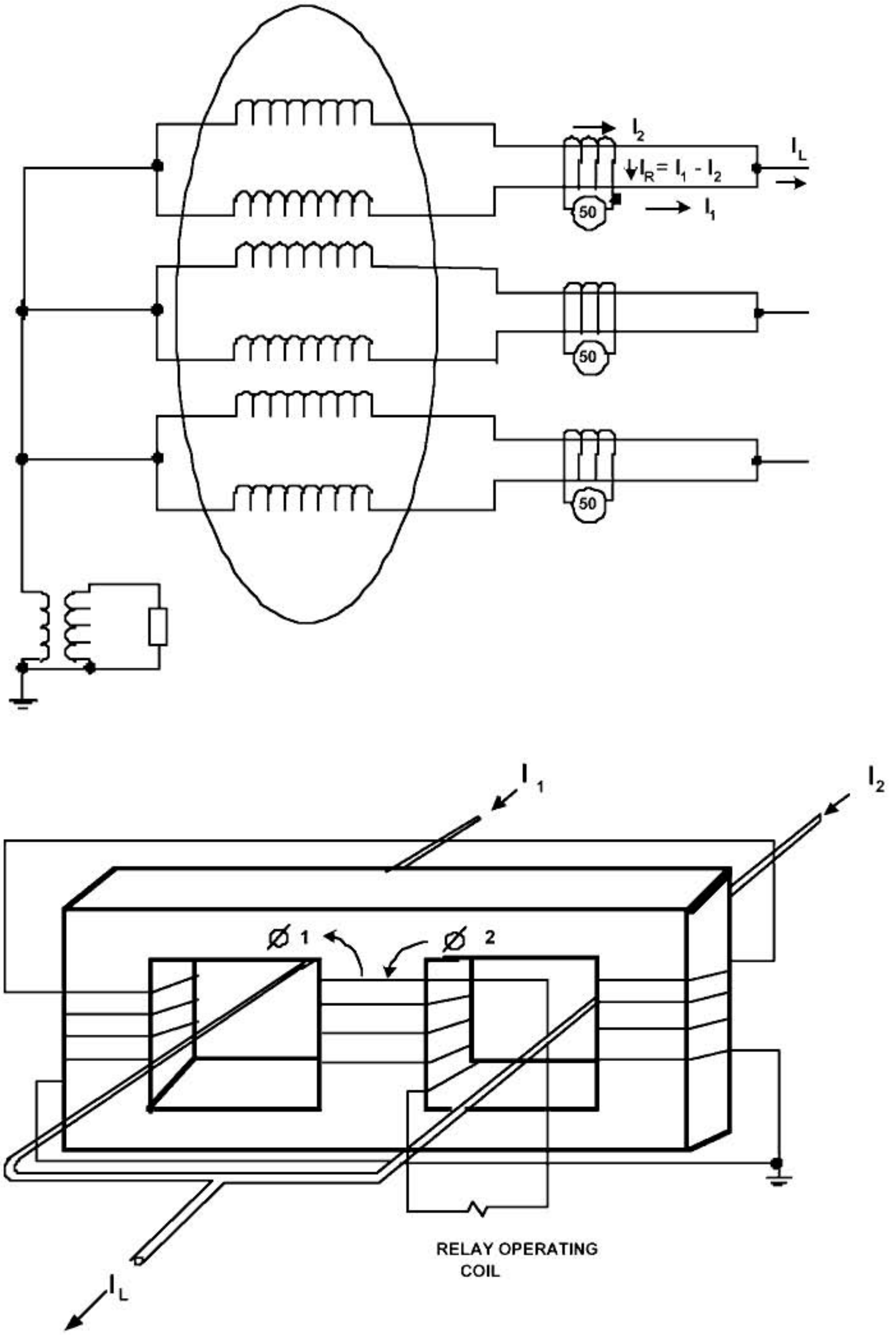


Figure 4-13—Split-phase protection using double-primary single-secondary CT

4.3.2.5.2 Turn-to-turn stator fault detection using unbalance overvoltage (59N)

For generators where the stator winding configuration does not allow the application of split-phase differential, a neutral voltage method may be used to detect turn-to-turn stator winding faults. Figure 4-14 illustrates this method. Three VTs are connected in wye, and the primary ground lead is tied to the generator neutral. The secondary is connected in a "broken delta" with an overvoltage relay connected across its open delta to measure unbalance voltage.

By connecting the primary ground lead to the generator neutral, the 59N relay is made insensitive to stator ground faults. The relay will, however, operate for turn-to-turn faults, which increase the unbalance voltage above low normal levels. This scheme is widely used outside of the U.S. The installation requires the cable from the neutral of the VT to the generator neutral be insulated for the system line-to-ground voltage. The 59N relay is tuned to fundamental frequency (60/50 Hz) voltage since some third harmonic voltages will be present across the broken-delta VT input.

One of the drawbacks of this scheme is that if the line to neutral insulated cable that connects the VT neutral to the generator neutral points sustains a ground fault, it will solidly ground the generator. For this reason, periodic testing of the cable is recommended.

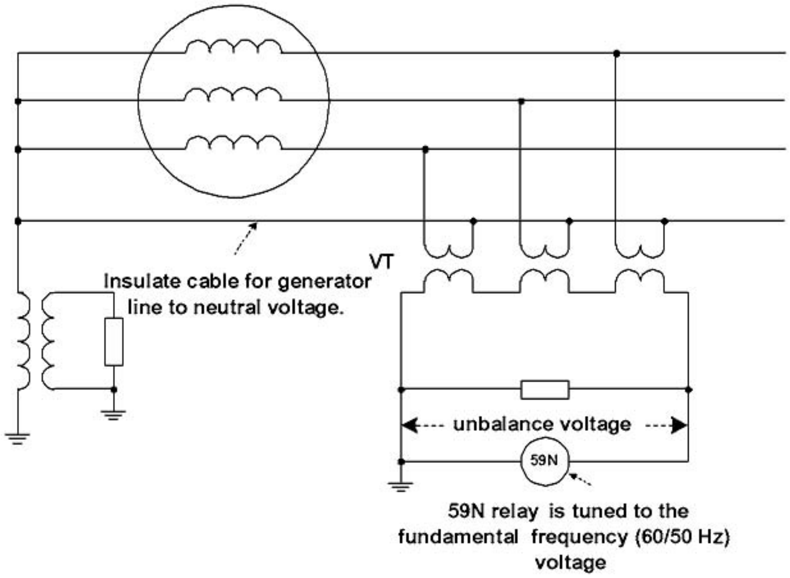


Figure 4-14—Turn-to-turn stator winding fault protection— zero-sequence unbalance overvoltage method (59N)

4.3.2.6 Backup protection

The type and sophistication of backup protection provided is dependent to some degree upon the size of the generator and on the method of connecting the generator to the system.

When a generator is connected to the system in the unit generator-transformer configuration, high-speed phase fault backup protection may be obtained by extending the protective zone of the unit transformer differential relay scheme to include the generator, the interconnecting leads, and the unit auxiliaries transformer. This backup is often referred to as the *overall differential scheme* and is illustrated in Figure 4-15.

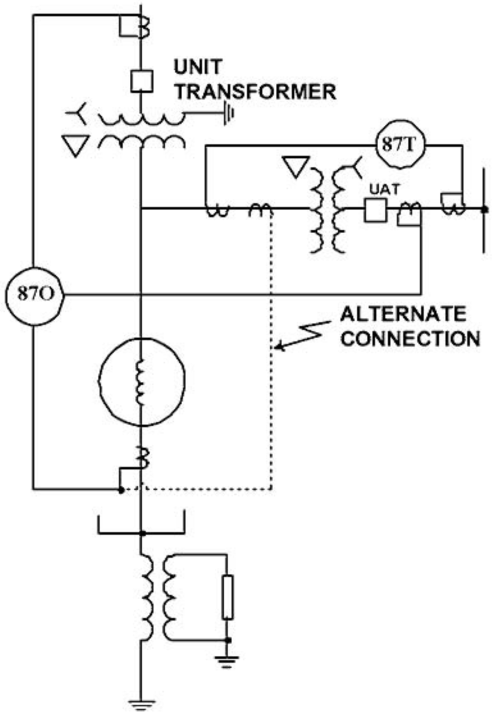


Figure 4-15—Generator phase fault backup overall differential scheme

In this arrangement, the CTs in the unit auxiliaries transformer circuit should be high-ratio CTs in order to balance the differential circuit. The required ratio may be obtained with a single bushing CT or with a combination of bushing and auxiliary CT.

In some cases, the unit auxiliaries transformer may be excluded from the overall differential scheme as indicated by the alternate connection. This approach may introduce a blind spot in the protection for the unit auxiliaries transformer. For faults near the high side of this transformer, the available fault current may be 150 to 200 times the rating of the CTs used in the differential scheme for the unit auxiliaries transformer. This high current level would drive the CTs into saturation, resulting in little or no current output to the differential relays. This blind spot is eliminated by connecting the overall differential scheme to the low side of the unit auxiliaries transformer. The overall scheme will detect the severe faults, while the unit auxiliaries differential will detect the low-level faults.

Figure 4-16 and Figure 4-17 illustrate the application of the overall differential scheme on a two-winding generator and on a cross-compound generator, respectively, where both types of generators are connected in a unit generator-transformer configuration.

Where generators are bused at generator voltage as shown in Figure 3-10 and Figure 3-11, or where generator breakers are used in the unit generator-transformer configuration as shown in Figure 3-8, the overall differential scheme is not applicable and a duplicate differential scheme is rarely used to provide phase fault backup protection.

In these configurations, it is common practice to use the unbalanced current protection (negative-sequence current relay) and system backup protection to provide backup for all generator phase faults. This protection is discussed in detail in 4.5.2 and 4.6 of this guide. This backup relaying is generally less sensitive than differential relaying and has time delay associated with it.

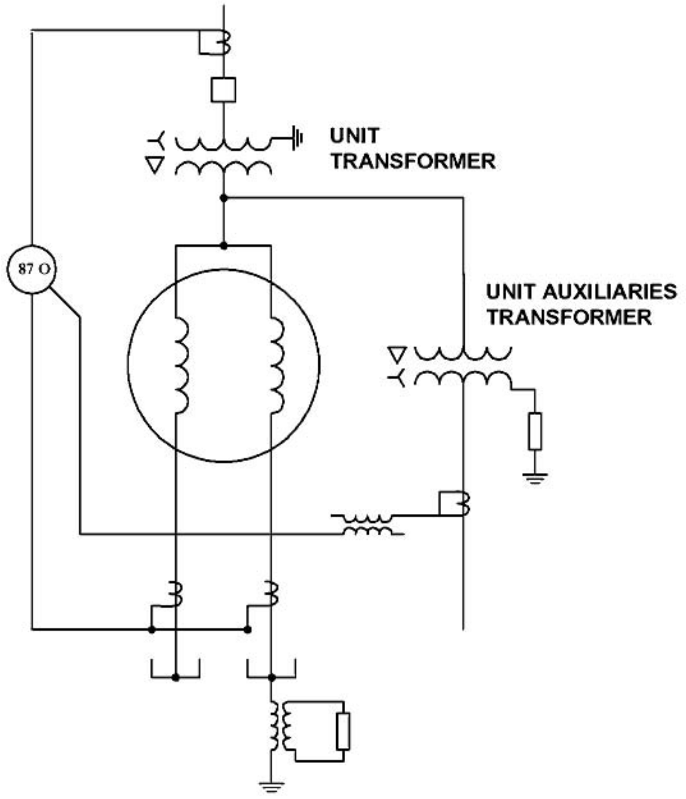


Figure 4-16—Phase fault backup for a two-winding generator

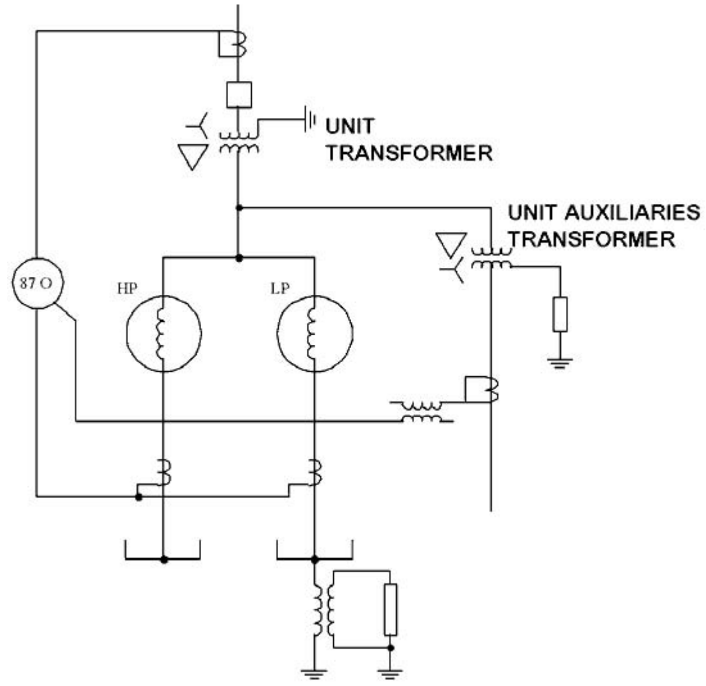


Figure 4-17—Phase fault backup for cross-compound generator

4.3.2.7 Tripping mode

It is common practice to have the primary and backup protection energize separate hand-reset multi-contact auxiliary relays. These auxiliary relays simultaneously initiate the following:

a) Trip the main generator breaker(s)
b) Trip the field and/or exciter breakers
c) Trip the prime mover
d) Turn on CO_2 internal generator fire protection if provided
e) Operate an alarm and/or annunciator
f) Transfer the station service to the standby source

4.3.3 Ground fault protection

Protective schemes that are designed to detect three-phase and phase-to-phase stator faults are not intended to provide protection for phase-to-ground faults in the generator zone. The degree of ground fault protection provided by these schemes is directly related to how the generator is grounded and, therefore, to the magnitude of the ground fault current available. The maximum phase-to-ground fault current available at the generator terminals may vary from three-phase fault current levels or higher to almost zero. In addition, the magnitude of stator ground fault current decreases almost linearly as the fault location moves from the stator terminals toward the neutral of the generator. For a ground fault near the neutral of a wye-connected generator, the available phase-to-ground fault current becomes small regardless of the grounding method.

As noted in the preceding subclause, differential relaying will not provide ground fault protection on high-impedance-grounded machines where primary fault current levels are limited to 3A to 25 A. Differential relaying schemes may detect some stator phase-to-ground faults depending upon how the generator is grounded. Figure 4-18 illustrates the approximate relationship between available ground fault current and the percent of the stator winding protected by a current-differential scheme. When the ground fault current level is limited below generator rated load current, a large portion of the generator may be unprotected.

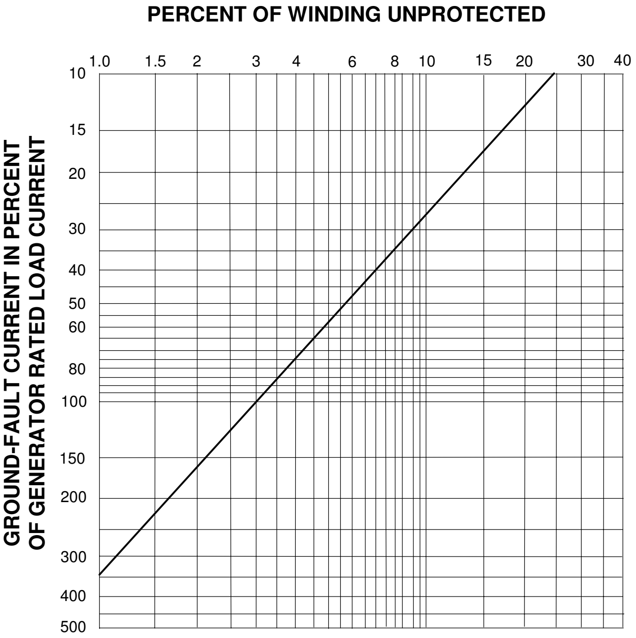


Figure 4-18—Percent of stator winding unprotected by differential relay for phase-to-ground fault

Since the available ground fault current may be small or limited to low values, it is common practice to provide separate sensitive ground fault protection for generators. Depending on the generator grounding method, the protection provided may include both primary and backup relaying or may be used to supplement whatever protection may be provided by differential relaying.

Numerous schemes have been developed and used to provide sensitive ground fault protection for generators and are discussed in considerable detail in IEEE Std C37.101-1993 [B62].

High-impedance grounding is generally used with unit system installations where a single generator or cross-compound generators are connected to the system through individual grounded wye-delta step-up transformers. The protection on a single unit generator-transformer arrangement is illustrated in Figure 4-19 and Figure 4-20.

Where cross-compound generators are bused at generator voltage or where a single generator has double windings, it is the practice to ground only one unit or winding as shown in Figure 4-20. Protection for both units and/or windings is provided by the one set of ground relays. Some types of 100% stator ground fault protection require relays for each neutral. The following discussion covers various schemes for the four grounding methods considered in 3.2 of this guide.

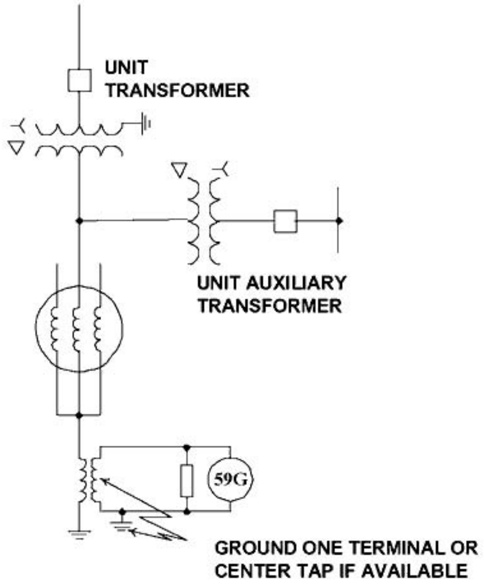


Figure 4-19—Generator ground fault protection for high-impedance grounded generator

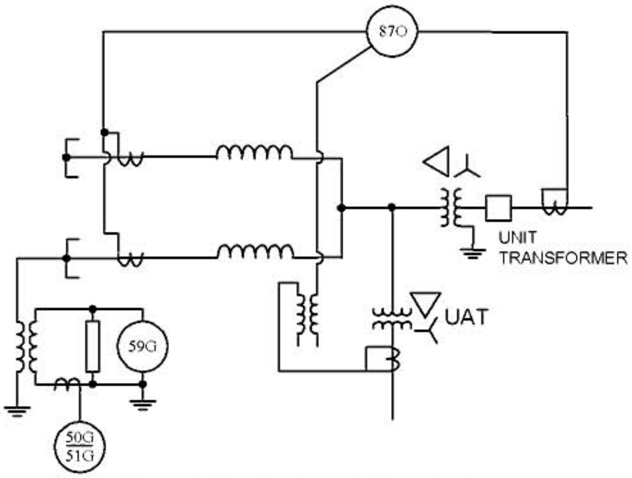
4.3.3.1 High-impedance grounding

As noted in 3.2.1, two types of high-impedance grounding are in use today:

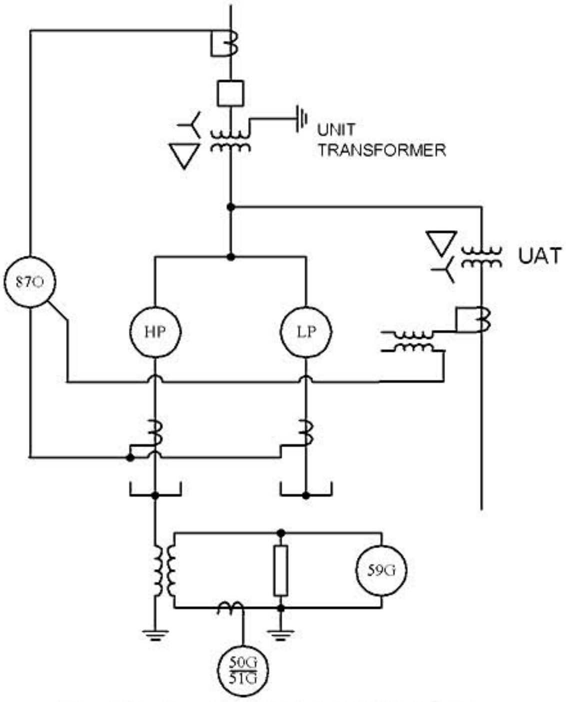
a) High-resistance grounding

b) Ground fault neutralizer grounding

In both cases, the ground fault current is limited to such low levels that differential relaying will not detect phase-to-ground faults. Therefore, for high-impedance grounded generators, it is common practice to provide separate primary and backup relaying for ground fault protection.



(A) - TWO-WINDING GENERATOR



(B) - CROSS-COMPOUND GENERATOR

Figure 4-20—Ground protection for a two-winding and/or cross-compound generator

4.3.3.1.1 Protection

An accepted protective scheme with the resistance-loaded distribution transformer method of grounding is a time-delay overvoltage relay, 59G, connected across the grounding impedance to sense zero-sequence voltage as shown in Figure 4-19.

The relay used for this function is designed to be sensitive to fundamental-frequency voltage and insensitive to third harmonic and other higher harmonic voltages that may be present at the generator neutral.

Since the grounding impedance is large compared to the generator impedance and other impedances in the circuit, the full phase-to-neutral voltage will be impressed across the grounding device for a phase-to-ground fault at the generator terminals. The voltage on the relay is a function of the distribution transformer ratio and the location of the fault. The voltage will be at a maximum for a terminal fault and decreases in magnitude as the fault location moves from the generator terminals toward the neutral.

Typically, the overvoltage relay has minimum pickup setting of approximately 5 V. With this setting and with typical distribution transformer ratios, this scheme is capable of detecting faults to within 2% to 5% of the stator neutral.

It should be noted that for personnel safety the distribution transformer secondary winding should be grounded at one point as shown in Figure 4-19. This point may be at one terminal of the secondary winding or at a center tap, if available.

The time setting for the voltage relay is selected to provide coordination with other system protective devices (see IEEE Std C37.101-1993 [B62]). Specific areas of concern include:

a) When grounded-wye/grounded-wye VTs are connected at the machine terminals, the 59G relay should be time coordinated with VT fuses for faults on the transformer secondary windings. If relay time delay for coordination is not acceptable, the coordination problem may be alleviated by grounding one of the secondary phase conductors instead of the secondary neutral. When this technique is used, the coordination problem still exists for ground faults on the secondary neutral. Thus its usefulness is limited to those applications where the exposure on the secondary neutral to ground faults is small.

b) The voltage relay may have to be coordinated with system relaying for system ground faults. System phase-to-ground faults will induce zero-sequence voltages at the generator due to capacitive coupling between the windings of the unit transformer. This induced voltage will appear on the secondary of the grounding distribution transformer and may cause operation of the zero-sequence voltage relay.

c) If a bus ground fault relay, device 59BN (see Figure 7-4, for example), is used to protect the section of bus between the generator and the unit step-up transformer, the voltage relay should also be coordinated with it. In particular, care should be taken that both devices have similar time-voltage characteristics, such as definite time or inverse time, in order to prevent mis-coordination.

In general, for cases a) and b) a long time-delay setting for an inverse time relay has been found necessary to provide adequate coordination with VT fuses and system ground relaying. Shorter time delays have been used where the VT secondary neutral is isolated and a secondary phase conductor grounded and where high-speed ground relaying is used on the high-voltage system.

A time-overcurrent relay with instantaneous element may be used as primary or backup protection when the generator is grounded through a distribution transformer with a secondary resistor. The CT supplying the overcurrent relay may be located in the generator neutral or in the secondary circuit of the distribution transformer as shown in Figure 4-21. When the CT is connected directly in the neutral, a 5:5 A CT ratio is employed. When the CT is connected in the distribution transformer secondary circuit, the CT ratio should be selected so that the maximum current in the 50/51G relay is approximately the same as the maximum generator ground fault amperes. In either case, a CT of high relaying accuracy (C100 or better) with a voltage rating determined by the generator phase-to-neutral voltage should be employed.

With the generator online, there will be a continuous flow of current in the 50/51G relay caused by the stray capacitances of the system being protected. This current will consist mostly of harmonics of the fundamental frequency, principally the third. It will vary directly with the real and reactive power on the machine, so that the maximum current flow will occur with the unit fully loaded. If the secondary resistor is properly selected, this value will seldom exceed 0.5 A, where the maximum fault current (in the generator and in the ground relay) approaches 10 A.

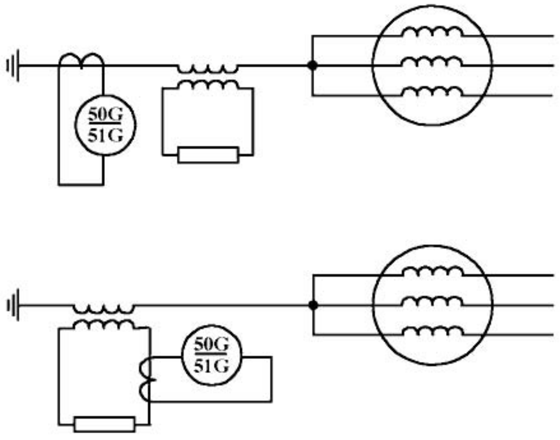


Figure 4-21—Backup ground overcurrent protection

It is important that the current in the 50/51G relay be measured with the unit running at full load. For example, if the relay pickup is set for 135% of the measured value, this protection will typically provide for 90% to 95% of the stator winding. See IEEE Std C37.101-1993 [B62]. A relay insensitive to harmonics may be set at a lower pickup, providing more protection to the stator.

Since a voltage may exist at the generator neutral when a fault occurs on the high-tension side of the GSU transformer, some time delay should be provided for the 50/51G time overcurrent (TOC) unit. Otherwise, the machine may be incorrectly tripped for a transmission system fault. The setting should also prove adequate for coordination with the generator potential transformer fuses.

The 50/51G relay should generally be equipped with an IOC unit. The IOC unit is extremely valuable in limiting machine damage, particularly in the case of nearly simultaneous ground faults on two different phases. However, if it is desired to coordinate the 50/51G relay with the generator potential transformer fuses, the IOC unit will have to be connected to alarm only. This will still prove of considerable value, since the action or inaction of this unit will aid in the frequently difficult task of determining fault location.

Some utilities have used overcurrent relays on generators grounded through a ground fault neutralizer. In this case an overcurrent relay will provide protection only in case of failure of the tunable reactor or distribution transformer.

As noted previously, the zero-sequence voltage relay will detect faults to within 2% to 5% of the stator neutral. There are several schemes for detecting ground faults at or near the neutral, thereby extending the ground fault protection to 100% of the stator winding.

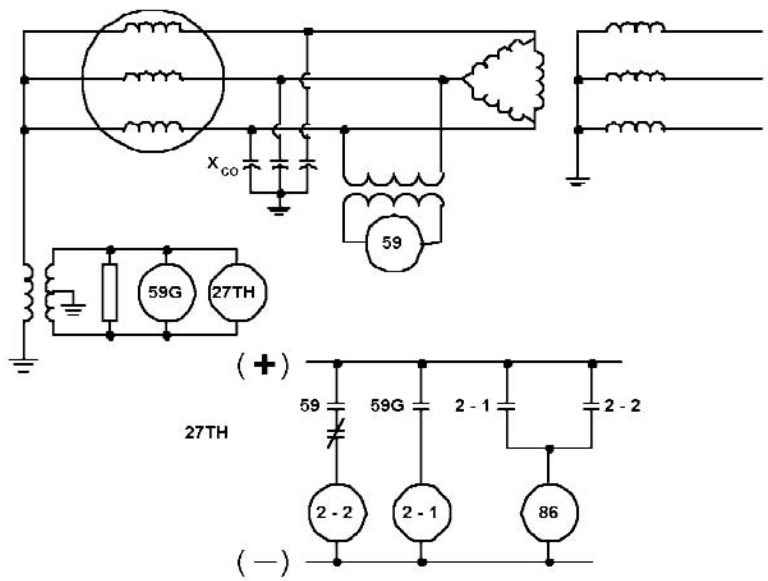
Several schemes use third harmonic voltage at the neutral or at the generator terminals as a means to detect faults near the stator neutral. These schemes supplement the fundamental frequency zero-sequence voltage relay and are illustrated in Figure 4-22, Figure 4-23, and Figure 4-24. Note that these schemes assume that adequate harmonic voltage is present at the neutral of the machine. Typical values needed are approximately 1% of rated voltage. Some generators are designed in a way that there is no significant amount of third harmonic voltage generated. In these situations 100% stator ground fault protection based on third harmonic voltage measurement may not be appropriate and other methods such as the one shown in Figure 4-25 should be considered.

In Figure 4-22, a third harmonic undervoltage relay (27TH) is placed across the grounding impedance. The relay operates (27TH contact closes) on the decrease in third harmonic voltage at the neutral that will occur during a stator phase-to-ground fault. The 27TH relay is supervised by a voltage relay to prevent the relay from operating when excitation is removed from the generator. Other means of supervising the 27TH relay may also be used.

In Figure 4-23, an overvoltage relay (59TH) is connected to measure the third harmonic voltage at the machine terminals. When a stator phase-to-ground fault occurs, there will be an increase in third harmonic voltage, which will cause relay operation.

Figure 4-24 illustrates a third harmonic voltage differential (59THD) scheme. This scheme compares the third harmonic voltage appearing at the neutral to the third harmonic voltage appearing at the generator terminals. The ratio of these third harmonic voltages is relatively constant for all load conditions. A stator phase-to-ground fault will disrupt this balance, thus causing operation of the differential relay.

One additional important advantage of this scheme is that it continuously monitors the grounding transformer primary and secondary connections and VT at the terminals of the machine. It operates for opens or shorts that might prevent the overvoltage relay or other relays from operating. Thus a problem could be detected before a stator ground occurs. This aspect of the protection scheme may favor an alarm rather than trip output. These characteristics also apply to Figure 4-22 and Figure 4-23.



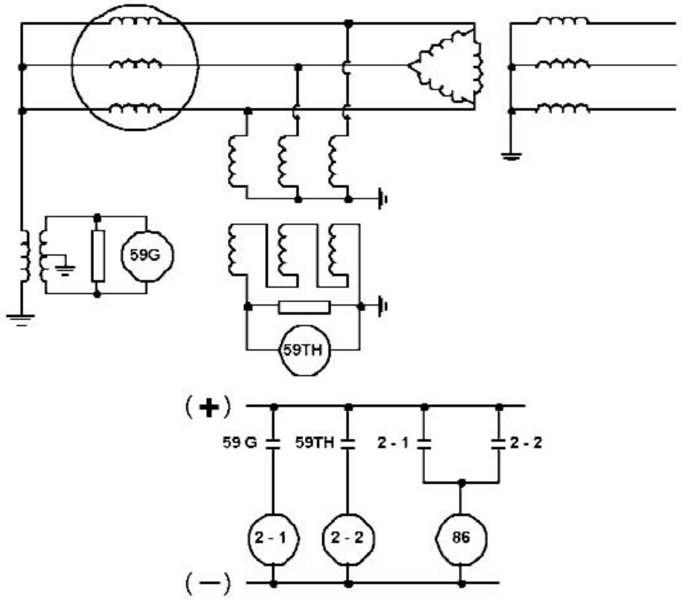
59 - INSTANTANEOUS OVERVOLTAGE RELAY.

59G - INSTANTANEOUS OVERVOLTAGE RELAY TUNED TO THE FUNDAMENTAL FREQUENCY.

27TH - INSTANTANEOUS UNDERVOLTAGE RELAY TUNED TO THE THIRD HARMONIC FREQUENCY.

2-1, 2-2 - TIMER.

Figure 4-22—Third harmonic undervoltage scheme for generator ground protection

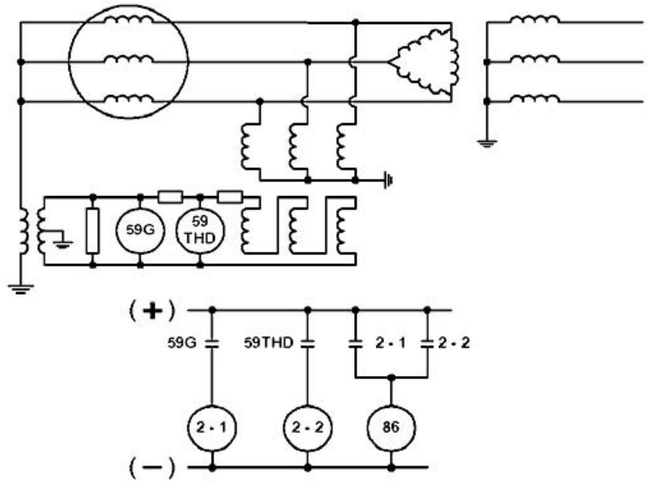


59TH - INSTANTANEOUS OVERVOLTAGE RELAY TUNED TO THE THIRD HARMONIC FREQUENCY.

59G - INSTANTANEOUS OVERVOLTAGE RELAY TUNED TO THE FUNDAMENTAL FREQUENCY.

2-1, 2-2 - TIMER.

Figure 4-23—Third harmonic overvoltage scheme for generator ground fault protection



59THD - INSTANTANEOUS THIRD HARMONIC VOLTAGE DIFFERENTIAL RELAY.

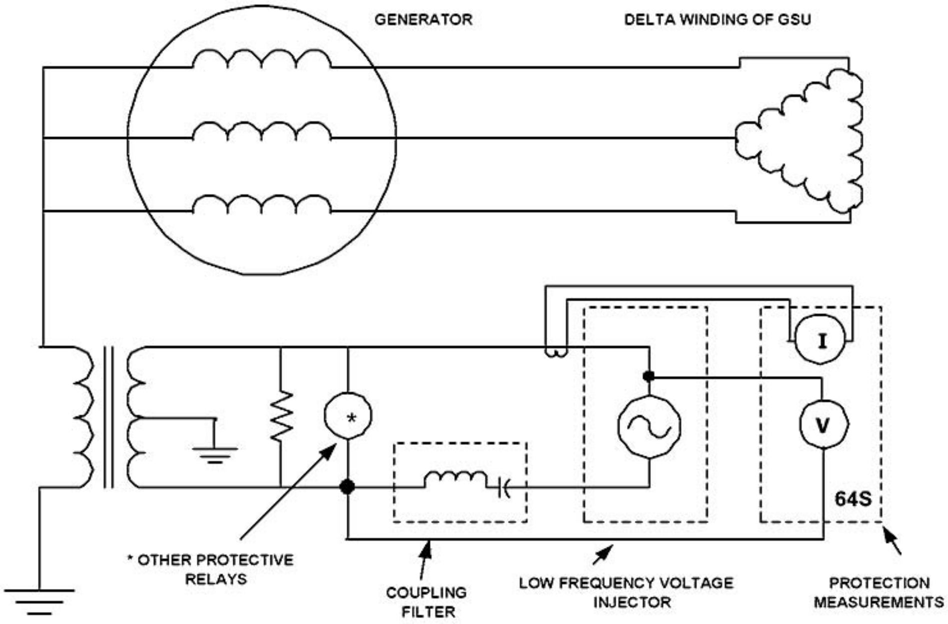
59G - INSTANTANEOUS OVERVOLTAGE RELAY TUNED TO THE FUNDAMENTAL FREQUENCY.

2-1, 2-2 - TIMER.

Figure 4-24—Third harmonic differential scheme for generator ground fault protection

Figure 4-25 illustrates a 100% stator ground fault protection scheme (64S) where a subharmonic voltage signal is injected through the grounding transformer. The coupling filter is tuned to block the fundamental frequency component of the signal. Under normal conditions the subharmonic current signal flows through the stator winding shunt capacitances to ground. When a stator phase-to-ground fault occurs, the shunt capacitances are short-circuited and the magnitude of the measured current signal increases. This change in signal level is detected by the relay. This scheme provides 100% ground fault protection with the generator energized or at standstill.

Figure 4-26[6] illustrates a scheme for the detection of ground faults for high-impedance grounded bused generators. The 67N allows selective detection of stator ground faults on high-impedance grounded generators, which are bused together. Most utilities in the U.S. do not bus high-impedance grounded machines. However, outside of the U.S., this is not the case. Typically this scheme is used on smaller size industrial generators.



NOTE 1—64S 100% stator ground fault protection with subharmonic voltage injection.

NOTE 2—Subharmonic injection frequency typically at 15 Hz to 20 Hz.

NOTE 3—Coupling filter (low pass or notch) tuned to subharmonic frequency.

NOTE 4—Measurement inputs tuned to respond to subharmonic frequency.

Figure 4-25—Subharmonic voltage injection scheme for generator ground fault protection

4.3.3.1.2 Tripping mode

In general, both the primary and backup protection is connected to trip and shut down the generator and the prime mover. Separate lockout relays should be used to distinguish phase faults from ground faults and/or primary from backup relay operation.

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[6] Notes in text, tables, and figures are given for information only and do not contain requirements needed to implement the standard.

In some instances where the generator is grounded through a ground fault neutralizer, the user may only alarm with the ground fault protection. The operator is thereby given time to analyze and assess the situation, and tripping may be delayed as long as an hour or two to permit fault isolation. Even though the ground fault current will be very small and may not damage the stator iron, the elevated voltages on the other two phases increase the risk that another ground fault may develop that will result in a very high phase-to-phase fault current.

Where the protection is connected to alarm, it may be necessary to remove the potential from the sensitive zero-sequence 59G voltage relays that have limited continuous overvoltage ratings so that they are not damaged. Neutral overvoltage during generator coast-down after tripping may exceed 59G relay coil voltage ratings. This may be accomplished with an auxiliary relay as shown in Figure 4-27. See IEEE Std C62.92.2 for ratings of the other components.

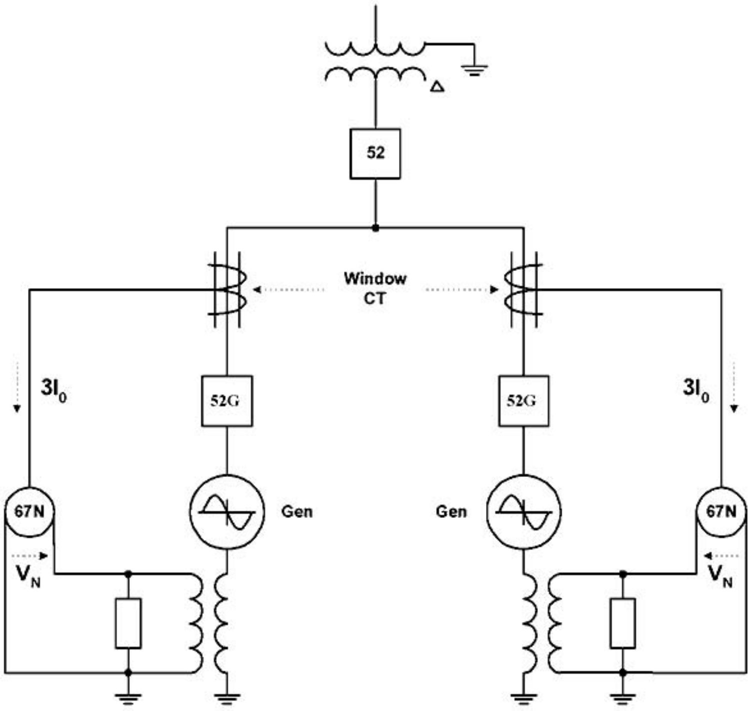

Figure 4-26—Directional ground fault protection for bused high-impedance grounded generators

4.3.3.2 Low-resistance grounding

As indicated in 3.2.2, the grounding resistor is selected to limit the generator's contribution to a single-phase-to-ground fault at its terminals to a range of current between 200 A and 150% rated full-load current. With this range of available fault current, differential relaying will provide some ground fault protection (see Figure 4-18). However, since the differential relaying will not provide ground fault protection for the entire stator phase winding, it is common practice to provide supplementary sensitive protection for ground faults. (See IEEE IAS Working Group on Generator Grounding, Parts 1–4 [B90].

This method of grounding is generally used where two or more generators are bused at generator voltage and connected to a system through one step-up transformer as illustrated in Figure 3-10, or connected directly to a distribution system as illustrated in Figure 3-11. When Figure 3-11 is used with resistor grounding, the feeders shall be of the three-wire type. The protection previously discussed will permit selective ground relaying of several generators.

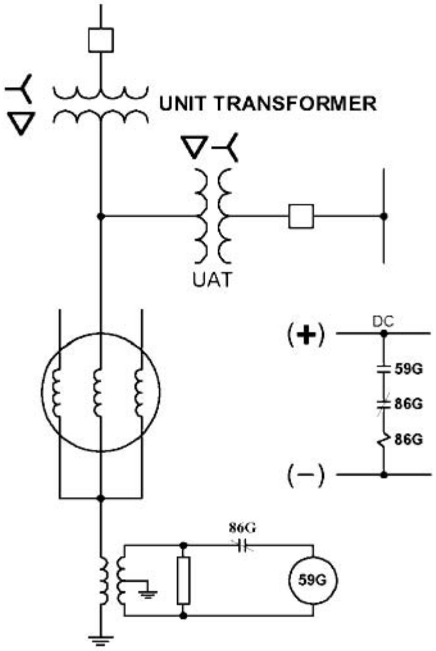

Figure 4-27—Scheme for removing potential from ground fault overvoltage relay when relay is used to alarm

4.3.3.2.1 Protection

Sensitive ground fault protection may be provided with either a current-polarized directional relay shown in Figure 4-28a or with a simple time-overcurrent relay connected as shown in Figure 4-28b and Figure 4-28c.

Figure 4-28a shows the current–polarized directional overcurrent scheme. The operating coil sees differential current of the phase CTs residual and the neutral CT, with an auxiliary CT used to match ratios. The neutral CT also provides current for the polarizing coil to ensure operation for only ground faults. The auxiliary transformer uses a 1.1 or 1.2 factor to “overcorrect” the mismatch between phases and neutral CT ratios. The factor biases the system in the non-trip direction to assure that there is restraining “torque” to prevent misoperation for external faults where unequal CT performance could cause a false residual current. An auxiliary transformer factor of 1 can be used where analysis shows that unequal CT performance will be negligible. This application provides sensitivity without a high operating coil burden.

Figure 4-28b illustrates the sensitively set time-overcurrent relay connected in differential neutral scheme. The time-overcurrent function, with a delay typically greater than 25 cycles, will ride through an unequal CT performance that may produce false residual currents during external faults.

Figure 4-28c shows the overcurrent relay using phase residual and neutral current scheme. This scheme uses an auxiliary CT to match CT ratios similar to scheme shown in Figure 4-28a. A time-overcurrent function with delay typically greater than 25 cycles should be used to ride through unequal CT performance that may produce false residual currents during external faults.

In all three approaches, the sensitive ground protection will only detect faults covered by the differential zone, thereby eliminating the need to time-coordinate these relays with other system relaying.

In addition to the proceeding protection, it is common practice to install a sensitive ground time-overcurrent relay in the generator neutral. This provides backup for the generator and external system ground faults.

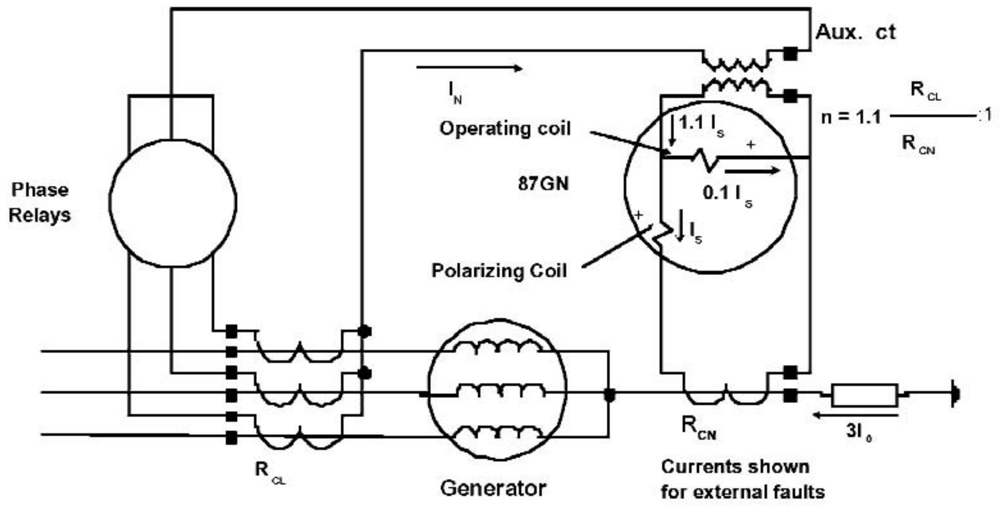

Figure 4-28a—Sensitive ground fault protection—current-polarized directional relay scheme

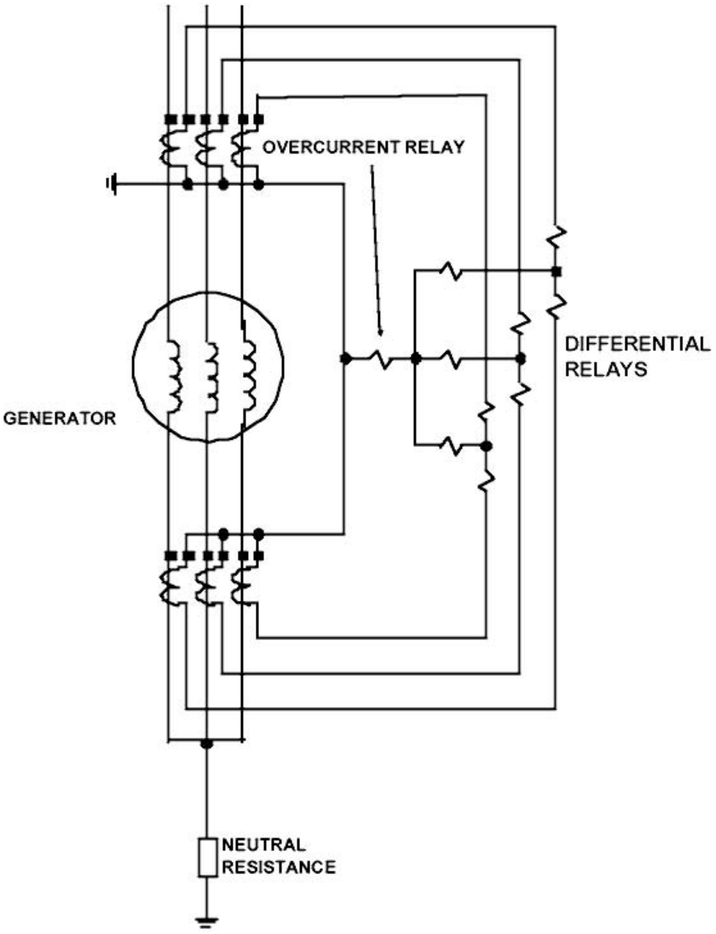

Figure 4-28b—Sensitive ground fault protection—overcurrent relay in differential neutral scheme

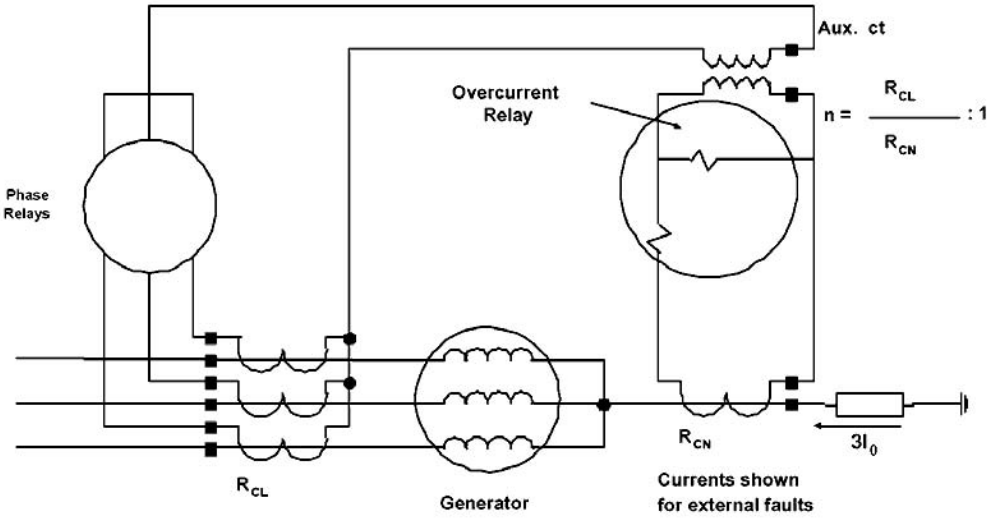

Figure 4-28c—Sensitive ground fault protection—overcurrent relay using phase residual and neutral CTs scheme

4.3.3.2.2 Tripping mode

The tripping mode is the same as for high-impedance grounding (4.3.3.1.2).

4.3.3.3 Reactance grounding

Reactance grounding is used where the generator is connected directly to an effectively grounded distribution system. With this method of grounding, the available ground fault current levels will range from 25% to 100% of the three-phase fault current. With this high level of fault current, differential relaying will be capable of providing almost complete protection of the stator phase winding for most ground faults. However, differential relaying may not detect high-resistance faults or faults near the generator neutral. Therefore, it is common practice to provide additional sensitive ground protection as backup for generator and system ground faults.

Backup protection is generally provided by a time-overcurrent relay connected to a CT in the generator neutral. The pickup of this relay should be set above the normal currents that flow in the neutral due to the unbalanced system loads and zero-sequence harmonic currents. Since this overcurrent relay will operate for system ground faults, it should be time coordinated with system ground relaying.

More sensitive ground fault protection may be provided with the directional overcurrent relay or with the simple overcurrent relay connected in the neutral of the differential scheme as described in 4.3.3.2.1.

4.3.3.3.1 Tripping mode

The tripping mode is the same as for high-impedance grounding (see 4.3.3.1.2).

4.3.3.4 Grounding transformer grounding

4.3.3.4.1 Protection

As discussed in 3.2.4, grounding may be provided by a zigzag transformer, or a grounded wye-delta transformer, or by a grounded wye-broken delta transformer with a resistor connected across a corner of the broken delta.

When a zigzag or grounded wye-delta transformer is used, the effective grounding impedance is selected to provide sufficient current for selective ground relaying. The available ground fault current is generally on the order of 400 A. These types of grounding transformers are generally used as an alternate grounding source when a generator with neutral reactance grounding is connected directly to a distribution system or as a bus grounding source where several ungrounded-wye or delta-connected generators are bused at generator voltage.

A typical application is illustrated in Figure 4-29. In this arrangement, the generators are ungrounded and the grounding bank is the sole path of ground fault current for faults in the generators or on the feeders.

Primary ground overcurrent relaying is required at each generator and feeder breaker. This protection could be sensitive IOC relaying. Backup protection may be provided by a time-overcurrent relay connected to a CT in the neutral of the grounding bank.

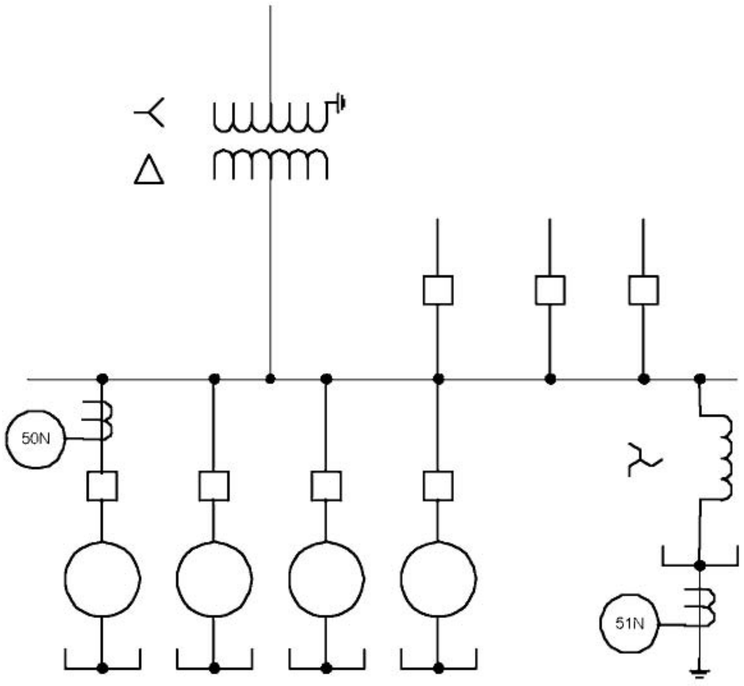

Figure 4-29—Ground fault protection with a zigzag ground bank

The grounded wye-broken delta transformer with a resistance in the corner of the broken delta is generally a high-resistance-grounded system that limits the single-phase-to-ground fault current to a range of 3 A to 25 A primary. This approach is generally used to provide a means for detecting ground faults in ungrounded generators prior to synchronizing the generator to the system or as a means for providing backup for high-impedance grounded generators. In the application, the grounding transformer is connected at the terminals of the generator and a zero-sequence overvoltage relay of the type described in 4.3.3.1.1 is connected across the resistance in the broken delta. The relay pickup setting and coordination is discussed in 4.3.3.1.1.

4.3.3.4.2 Tripping mode

The tripping mode is the same as for high-impedance grounding (see 4.3.3.1.2).

4.3.3.5 Hybrid generator grounding

In industrial applications, many generators are directly connected to a bus that services local load. Figure 4-30 illustrates this type of configuration. Hybrid grounding may be applied to these types of generators. (See IEEE IAS Working Group on Generator Grounding, Parts 1–4 [B90] and Moody et al. [B93].)

The generator is both high-impedance and low-impedance grounded. Under normal operating conditions, both generator ground sources are operated in parallel. For a ground fault on the industrial system the ground fault current contribution from the generator will typically be almost entirely from the low-impedance (200 A to 400 A) source.

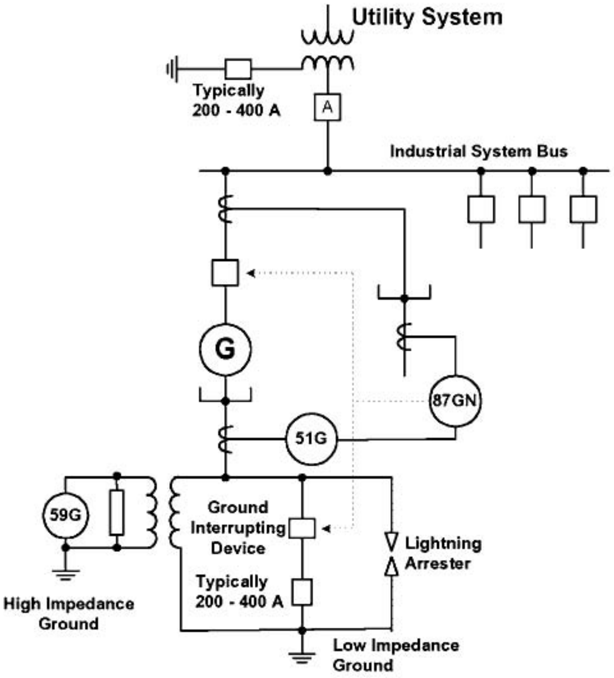

Figure 4-30—Hybrid grounding

This provides the required level of system ground current for proper ground relay operation allowing the generator to supply the local load when the utility system is unavailable (breaker A open). When there is a ground fault in the generator stator windings or associated bus connection to the generator breaker, the ground differential (87GN) will operate to initiate a unit shutdown. As part of the generator tripping, the ground interruption device in series with the low-impedance grounding resistor is tripped. This leaves the generator grounded through only the high-impedance path, which typically reduces ground current to the 3 A to 5 A level. This greatly reduces stator ground fault damage during the generator or "coast down." Studies (see Powell [B78]) have shown that major damage occurs after generator tripping during this coast-down period. Reducing fault current during this period greatly reduces stator ground fault damage.

Hybrid grounding is a new approach to reducing stator ground fault damage with limited in-service experience. Careful consideration should be given to the proper selection and appropriate rating of components for this application.

4.4 Generator rotor field protection

This subclause is primarily concerned with the detection of ground faults in the field circuit. Other protection for the field circuit is covered in 4.5.1.

The field circuit of a generator is an ungrounded system. As such, a single ground fault will not generally affect the operation of a generator. However, if a second ground fault occurs, a portion of the field winding will be short-circuited, thereby producing unbalanced air gap fluxes in the machine. These unbalanced fluxes may cause rotor vibration that may quickly damage the machine; also, unbalanced rotor winding and rotor body temperatures caused by uneven rotor winding currents may cause similar damaging vibrations. The probability of the second ground occurring is greater than the first, since the first ground establishes a ground reference for voltages induced in the field by stator transients, thereby increasing the stress to ground at other points on the field winding.

4.4.1 Protection

There are several methods in common use for detecting rotor field grounds.

4.4.1.1 Field ground detection using a dc source

In the method shown in Figure 4-31, a dc voltage source in series with an overvoltage relay coil is connected between the negative side of the generator field winding and ground. A ground anywhere in the field will cause the relay to operate. A brush is used to ground the rotor shaft since the bearing oil film may insert enough resistance in the circuitry so that the relay would not operate for a field ground. One to three seconds of time delay is normally used with this relay in order to prevent unnecessary operations for momentary transitory unbalances of the field circuit with respect to ground. These momentary unbalances may be caused by the operation of fast response thyristor type excitation systems.

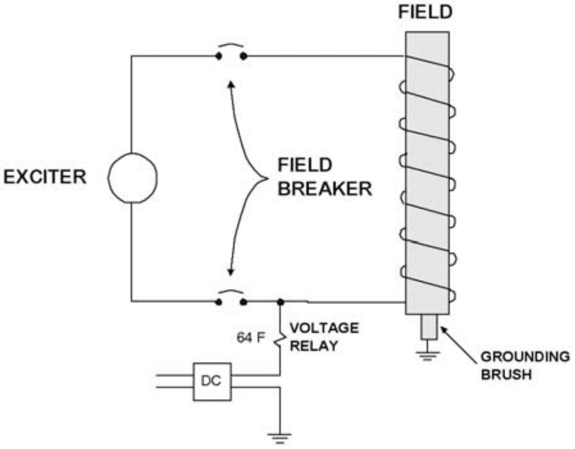

Figure 4-31—Field ground detection using a dc source

4.4.1.2 Field ground detection using a voltage divider

Figure 4-32 illustrates a second method used to detect field circuit grounds. It is similar to ground detection schemes used to sense grounds on substation control batteries. This method uses a voltage divider and a sensitive overvoltage relay between the divider midpoint and ground. A maximum voltage is impressed on the relay by a ground on either the positive or negative side of the field circuit. However, there is a null point between positive and negative where a ground fault will not produce a voltage across the relay unless the polarity on the ground detector is reversed. This generator field ground relay is designed to overcome the null problem by using a nonlinear resistor (varistor) in series with one of the two linear resistors in the voltage divider. The resistance of the nonlinear resistance varies with the applied voltage. The divider is proportioned so that the field winding null point is at the winding midpoint when the exciter voltage is at rated voltage. Changes in exciter voltage will move the null point from the field winding center.

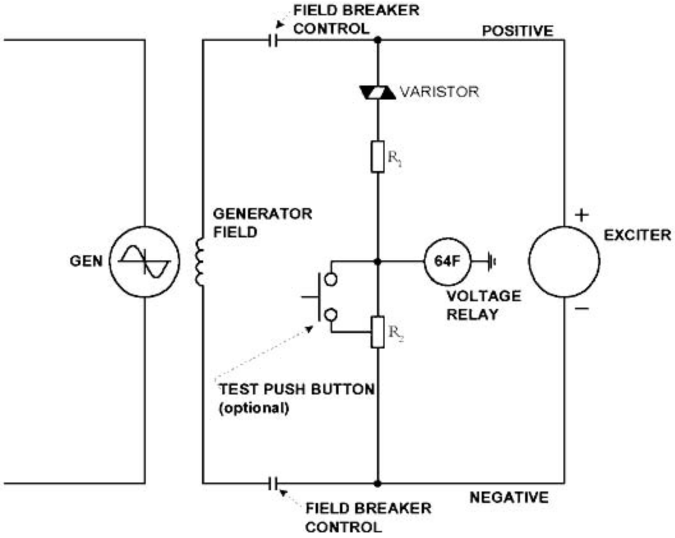

Figure 4-32—Field ground detection using a voltage divider

4.4.1.3 Field ground detection using pilot brushes

On a brushless excitation system, continuous monitoring for field ground is not possible with conventional field ground relays since the generator field connections are contained in the rotating element.

Figure 4-33 illustrates the addition of a pilot brush or brushes to gain access to the rotating field parts. Normally this is not done since eliminating the brushes is one of the advantages of a brushless system. However, detection systems may be used to detect field grounds if a collector ring is provided on the rotating shaft along with a pilot brush that may be periodically dropped to monitor the system. The ground check may be done automatically by a sequencing timer and control or by the operator. The brushes used in this scheme are not suitable for continuous contact with the collector rings. The field circuit impedance to ground is one leg of a Wheatstone bridge connected via the brush. A ground fault shorts out the field winding to rotor capacitance, C_R, which unbalances the bridge circuit. If a voltage is read across the 64F relay, then a ground exists. For brushless machines, resistance measurements may be used to evaluate the integrity of the field winding.

4.4.1.4 Field ground detection for brushless machines with telemetry

Figure 4-34 illustrates a method for continuous monitoring of field grounds on brushless machines without using pilot brushes. The scheme shown here uses light emitting diodes (LEDs) and an infrared detector. Other media such as radio telemetry can also be applied.

The relay's transmitter is mounted on the generator field diode wheel. Its source of power is the ac brushless exciter system. Two leads are connected to the diode bridge circuit of the rotating rectifier to provide this power. Ground detection is obtained by connecting one lead of the transmitter to the negative bus of the field rectifier and the ground lead to the rotor shaft. Sensing current is determined by the field ground resistance and the location of a fault with respect to the positive and negative bus. The transmitter detects the resistance change between the field winding and the rotor core.

The transmitter LEDs emit light for normal conditions. The receiver is mounted on the exciter housing. The receiver's infrared detectors sense the light signal from the LED across the air gap. Upon detection of a fault, the LEDs are turned off. Loss of LED light to the receiver will actuate the ground relay and initiate a trip or alarm. The relay has a settable time delay of up to 10 s.

4.4.1.5 Field ground detection using low-frequency square-wave voltage injection

Figure 4-35 shows a field ground fault detection scheme using a low-frequency square-wave injection principle. This principle has been widely used in Europe with great success, but until recently, it was not available in a multifunction digital relay. As illustrated in Figure 4-35, a +15 V square-wave signal is injected into the field. The return signal waveform is measured and the insulation resistance is estimated. The injection frequency setting is adjusted (0.1 Hz to 1.0 Hz) based on the field winding capacitance. The measurement on the return signal is taken after the signal reaches steady state. The relay set points are in ohms typically with a 20 kW alarm and 5 kW trip or critical alarm. In addition, digital relays may provide real-time monitoring of actual insulation resistance so deterioration with time may be monitored. The passive coupling network is used to isolate high dc field voltages from the relay.

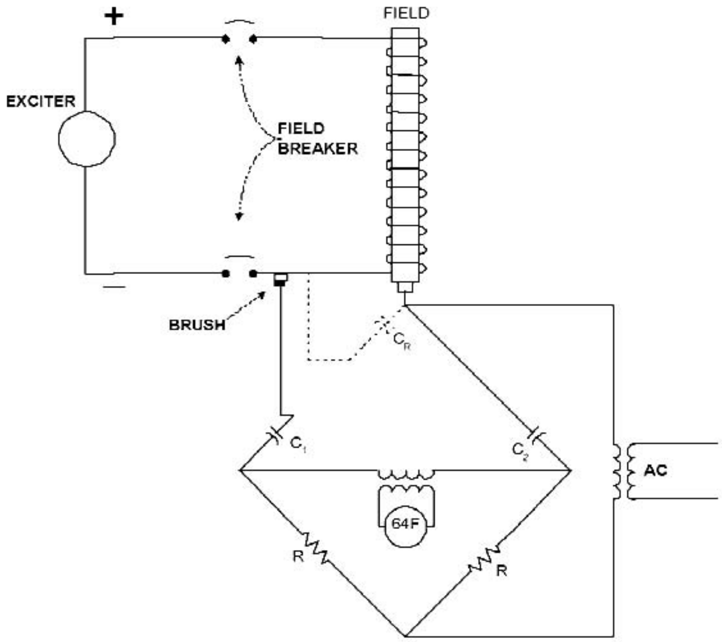

Figure 4-33—Field ground detection using pilot brushes

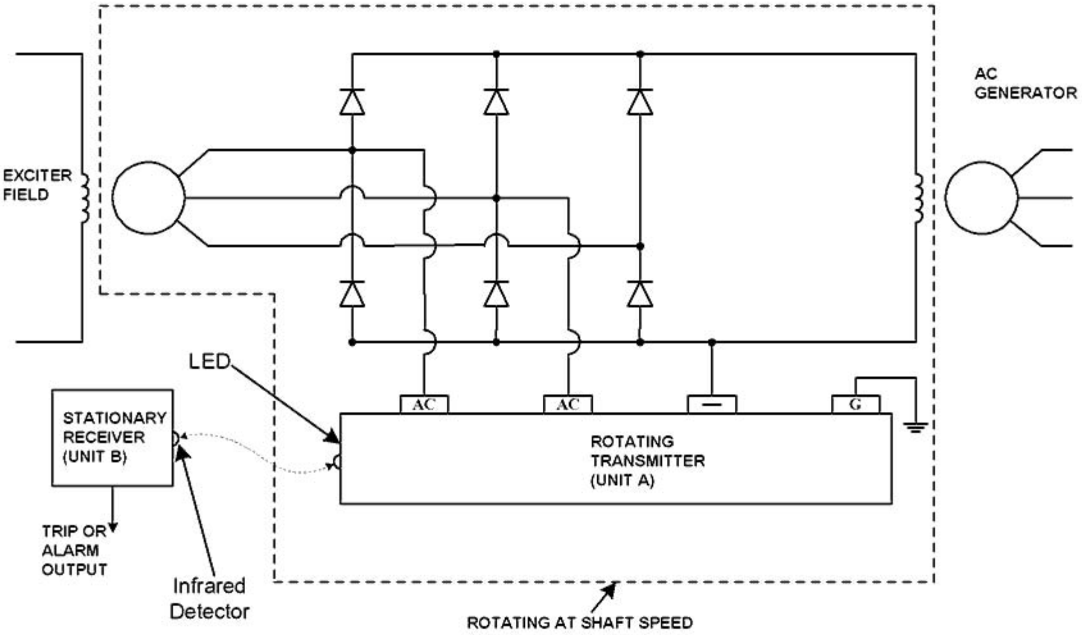

Figure 4-34—Field ground detection for brushless machines

Backup protection for the previously described schemes usually consists of vibration detecting equipment. Contacts are provided to trip the main and field breakers if vibration is above that associated with normal short-circuit transients for faults external to the unit. A brush seating verification scheme is also sometimes used when brushes are retractable. The scheme requires two brushes with a power supply that by relay action will indicate if either brush does not seat, and therefore, the ground detection is not functioning.

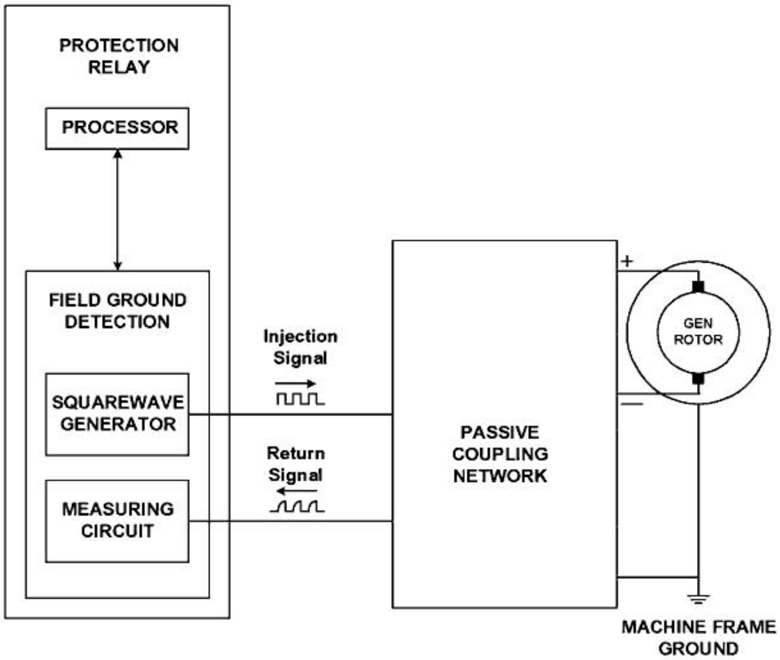

Figure 4-35—Field ground protection using an injection voltage signal

4.4.2 Tripping mode

Tripping practices within the industry for field ground relaying are not well established. Some users trip while others prefer to alarm, thereby risking a second ground fault and major damage before the first ground is cleared. The probability of a second ground fault occurring is greater after the first fault has occurred because field insulation has deteriorated and the first ground has established a ground reference. The user that alarms typically attempts to locate and clear the ground. If the ground could not be found within a reasonable period, the unit is removed from service in an orderly manner. Major field damage has occurred due to a second ground fault occurring before the unit could be removed from service.

4.5 Generator abnormal operating conditions

This subclause describes those hazards to which a generator may be subjected that may not necessarily involve a fault in the generator. It discusses the typical means for detecting these abnormal operating conditions and the tripping practices.

4.5.1 Loss of field

The source of excitation for a generator may be completely or partially removed through such incidents as accidental tripping of a field breaker, field open circuit, field short circuit (flashover of the slip rings), voltage regulation system failure, or the loss of supply to the excitation system. Whatever the cause, a loss of excitation may present serious operating conditions for both the generator and the system.

4.5.1.1 Combustion gas and steam turbine (round rotor) generators

When a generator loses excitation, it will overspeed and operate as an induction generator. It will continue to supply some power to the system, and it will receive its excitation from the system in the form of vars. The machine slip and power output will be a function of initial machine loading, machine and system impedances, and governor characteristic. High system impedances tend to produce a high slip and a low power output.

If a generator is operating initially at full load when it loses excitation, it will reach a speed of 2% to 5% above normal. This overspeed condition may be especially harmful to steam turbine driven generators. The level of kvars drawn from the system may be equal to or greater than the generator kVA rating. If a generator is initially operating at reduced loading (for instance, 30% loading), the machine speed may only be 0.1% to 0.2% above normal, and it will receive a reduced level of vars from the system.

In general, the severest condition for both the generator and the system is when a generator loses excitation while operating at full load. For this condition, the stator currents may be in excess of 2.0 pu, and since the generator has lost synchronism, there may be high levels of current induced in the rotor. These high current levels may cause damaging overheating of the stator windings. In addition, since the loss-of-field condition corresponds to operation at very low excitation, overheating of the end portions of the stator core may result. No general statements may be made with regard to the permissible time a generator may operate without field, and the generator manufacturers should be consulted for guidance.

With regard to effects on the system, the var drain from the system may depress system voltages and thereby affect the performance of generators in the same station, or elsewhere on the system. In addition, the increased reactive flow across the system may cause voltage reduction and/or tripping of transmission lines and thereby adversely affect system stability.

When a lightly loaded machine loses field, the effects will be less damaging to the machine, but the var drain may still be detrimental to the system. In addition to complete loss of excitation, protection should be considered for partial loss of excitation that results in prolonged operation in the underexcited region. This condition may occur for a failure in the voltage regulator system or when the voltage regulator has been automatically or manually placed on manual control. There are two considerations for protection against operation below the underexcited region of the generator capability curve (GCC).

The first consideration is damage to the unit. The underexcited limit arc of the GCC represents the thermal damage limitation of the stator end iron. The primary protection for this is the minimum excitation limiter (also known as the *underexcited reactive ampere limit*) of the excitation system control. The second consideration for operating in the underexcited region is the steady-state stability limit (SSSL). This limit is a function of the unit and the system that it is connected to.

4.5.1.2 Hydrogenerators (salient-pole rotor)

Due to saliency, the normal hydrogenerator may carry 20% to 25% of normal load without field and not lose synchronism. The actual load carrying capability is a function of machine and system characteristics. Also, operation with nearly zero field and at reduced load is often necessary to accept line charging current. However, if a loss of field occurs when a hydrogenerator is carrying full load, it will behave and produce the same effects as a steam turbine generator. High stator and induced field currents may damage the stator winding, the field windings, and/or the amortisseur windings, and the unit will impose a var drain on the system.

4.5.1.3 Protection

An accepted method for detecting a generator loss of field is the use of distance relays to sense the variation of impedance as viewed from the generator terminals. It has been shown that when a generator loses excitation while operating at various levels of loading, the variation of impedance as viewed at the machine terminals will have the characteristics shown on the RX diagram in Figure 4-36.

In this diagram, curve (a) shows the variation of impedance with the machine operating initially at or near full load. The initial load point is at C, and the impedance locus follows the path C-D. The impedance locus will terminate at D to the right of the ($-x$) ordinate and will approach impedance values somewhat higher than the average of the direct and quadrature-axis subtransient impedances of the generator. Curve (b) illustrates the case in which a machine is initially operating at 30% load and underexcited. In this case, the impedance locus follows the path E-F-G and will oscillate in the region between points F and G. For a loss of field at no load, the impedance as viewed from the machine terminals will vary between the direct and quadrature-axis synchronous reactances (X_d, X_q). In general, for any machine loading, the impedance viewed from the machine terminals will terminate on or vary about the dashed curve (D-L).

There are two types of distance relaying schemes used for detecting the impedances seen during a loss of field. The two schemes differ mainly in that scheme 1 uses a negative offset mho element and scheme 2 uses a positive offset mho element with directional unit supervision.

Scheme 1 is shown in Figure 4-37 where one or two negative offset mho units are used to protect a machine.

These relays are applied to the generator terminals and set to look into the machine. On small or less important units, only a single relay would be used with the diameter of its circular characteristics set equal to synchronous reactance of the machine (X_d) and with an offset equal to one half of the direct axis transient reactance (X'_d). Time delay of 0.5 s to 0.6 s would be used with this unit in order to prevent possible incorrect operations on stable swings. Transient stability studies are used to determine the proper time-delay setting.

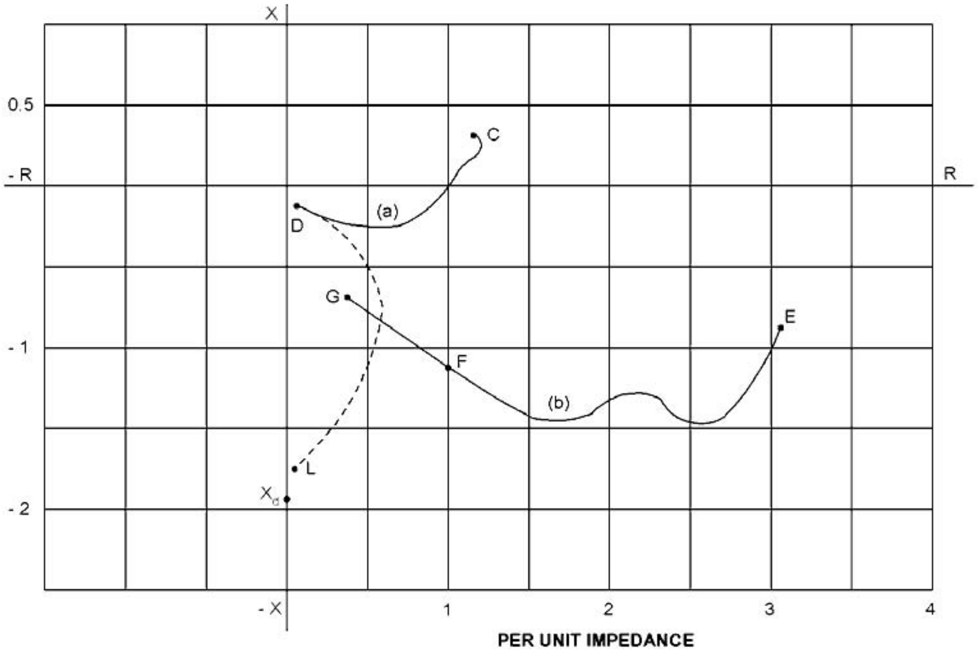

Figure 4-36—Loss-of-excitation characteristics for a tandem compound generator

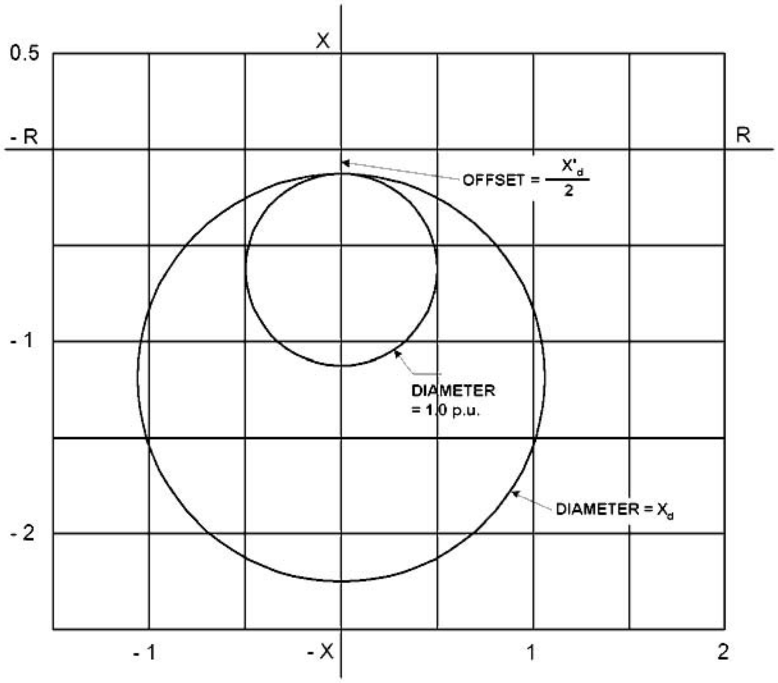

Figure 4-37—Generator protection using two loss-of-excitation relays—scheme 1

Depending upon machine and system parameters, two relays are sometimes used as shown in Figure 4-37. Also, with the advent of MGPSs, the use of two zones is becoming more prevalent. The relay with 1.0 pu (generator base) impedance diameter will detect a loss of field from full load down to about 30% load. A small time delay of about 0.1 s is suggested for security against transients.

The function of this protection zone is to provide fast protection for more severe conditions in terms of machine damage and adverse affects on system. The second relay would have a diameter setting equal to X_d and would use a time delay of 0.5 s to 0.6 s. Both units would be set with an offset equal to one half of the transient reactance.

Scheme two is illustrated in Figure 4-38. This scheme uses a combination of an impedance unit, a directional unit, and an undervoltage unit applied at the generator terminals and set to look into the machine. The Zone 2 impedance unit is set to coordinate with the SSSL and the minimum excitation limiter.

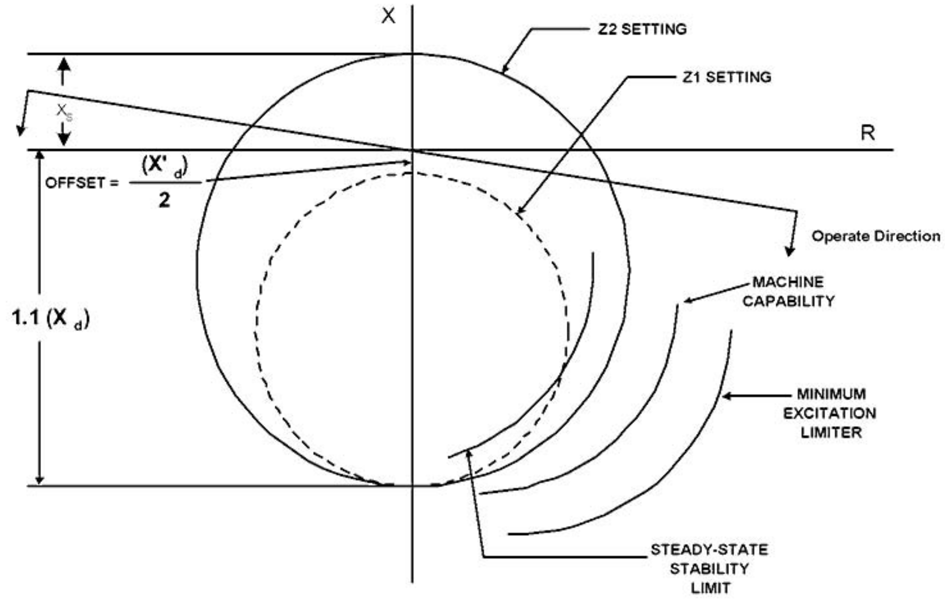

Figure 4-38—Generator protection using two loss-of-excitation relays—scheme 2

The SSSL may be plotted on the PQ plane for cylindrical rotor machines as a circle described by Equation (4.1) and Equation (4.2):

$$\text{Center offset} = -\frac{1}{2}\mathrm{kV}_{LL}^{2}\left(\frac{1}{X_d}-\frac{1}{X_S}\right) = \mathrm{MVA}_{3(} \tag{4.1}$$

$$\text{Radius} = \frac{1}{2}\mathrm{kV}_{LL}^{2}\left(\frac{1}{X_d}+\frac{1}{X_S}\right) = \mathrm{MVA}_{3\phi} \tag{4.2}$$

Where kV_{LL} is the machine line-to-line voltage rating in kV; X_d is the machine direct axis reactance in primary ohms; and X_s is the impedance of the system beyond the terminals of the machine in primary ohms.

In order to set the mho element, it is necessary to plot the SSSL on the RX plane. The SSSL may be plotted on the RX plane as a circle described by Equation (4.3) and Equation (4.4):

$$\text{Center offset in ohms} = -\frac{1}{2}(X_d - X_s) \tag{4.3}$$

$$\text{Radius in ohms} = \frac{1}{2}(X_d + X_s) \tag{4.4}$$

Where X_d is the machine direct axis reactance in relay secondary ohms, and X_s is the impedance of the system beyond the terminals of the machine in relay secondary ohms.

The positive offset mho element is then set with 10% margin beyond the SSSL using the following equations derived from Equation (4.3) and Equation (4.4):

$$\text{Reach (diameter)} = (1.1X_d + X_s)$$

$$\text{Offset} = X_s$$

The machine capability curve and the minimum excitation limiter may be plotted on the RX plane by taking points on the curve in the PQ plane and converting them to impedance values using Equation (4.5).

$$Z_{RX} = \frac{(\mathrm{kV}_{LL})^2}{\mathrm{MVA}_{PQ}} \frac{CTR}{VTR} \tag{4.5}$$

Where Z_{RX} is the point to be plotted on the RX diagram in relay secondary ohms; MVA $_{PQ}$ is the point taken from the PQ diagram in $\mathrm{MVA}_{3\phi}$; kV_{LL} is the machine rated voltage times 0.95, which is the minimum voltage that the GCC is valid for; and CTR and VTR are the ratios of the CTs and VTs connected to the relay. In this calculation, 0.95 pu voltage is used because it is the minimum voltage that the GCC is valid for. Under conditions of underexcitation, it is likely that the system voltages may be depressed from normal. If you use nominal generator voltage in the conversion, it pushes the GCC farther away from the loss-of-field element characteristic in the RX plane. Thus, 0.95 represents the worst-case situation for coordinating the loss-of-field element characteristic with the field GCC.

Since the impedance unit has a positive offset, it is supervised by a directional element to prevent pickup for close-in faults on the system. During abnormally low excitation conditions, such as might occur following a failure of the minimum excitation limiter, both the directional and impedance units operate and sound an alarm, allowing a station operator to correct the condition. In many cases, this also starts a timer to trip the unit if the condition cannot be corrected before the unit goes unstable or is damaged. This timer would typically be set at 1 min.

Should a low-voltage condition also exist, indicating a complete loss-of-field condition where the connected system is not capable of supplying adequate reactive power, the undervoltage unit would operate and initiate tripping with a time delay of 0.25 s to 1.0 s. The shorter time would be used if there is no Zone 1 element. The longer time would be used if two zones are applied. The undervoltage unit is typically set from 0.8 pu to 0.9 pu of machine rating.

Two relays may also be used in this scheme, with the second (shown as $Z1$ on Figure 4-38) set with an offset equal to $X'_d/2$ and with the long reach intercept equal to 1.1 times X_d. In this case, the relay with the $Z1$ setting should trip with a time delay of 0.2 s to 0.3 s to ride through stable swings and system transients.

In both of the previous schemes where two relay units are used, one may be considered primary protection and the second as backup. However, in some instances no backup for the loss-of-field relay is used. In such instances, dependence is placed upon an operator to trip the machine before it is damaged if the primary protection and that inherent in the excitation system fails.

When applying this protection to hydrogenerators, there are other factors that may have to be considered. Since hydrogenerators may be operated on occasion as synchronous condensers, it is possible for the above loss-of-field relaying schemes to operate unnecessarily when the generator is operated underexcited, that is, taking in reactive power approaching machine rating. To prevent unnecessary operations, an undervoltage relay may be used to supervise the distance relaying schemes. The dropout level of this undervoltage relay would be set at 90% to 95% of rated voltage, and the relay would be connected to block tripping when it is picked up and to permit tripping when it drops out. This combination will provide protection for almost all loss-of-field conditions but may not trip when the generator is operating at light load, since the voltage reduction may not be sufficient to cause relay dropout.

A system separation that leaves transmission lines connected to a hydrogenerator may also cause unnecessary operation of the distance relay schemes. For this condition, the hydrogenerator may temporarily reach speeds and frequencies up to 200% of normal. It may not be desirable to trip for this condition. At frequencies above 60 Hz, the angle of maximum torque for some distance relays will shift farther into the fourth quadrant and the circle diameter may increase by 200% to 300%. With this shift and increase in characteristic, it is possible for the relay to operate on the increased line charging current caused by the temporary overspeed and overvoltage condition. Unnecessary operation of the distance relay schemes for this condition may be prevented by supervising the schemes with either an undervoltage relay or an overfrequency relay. The undervoltage relay would be set and connected as previously discussed. The overfrequency relay would be set to pick up at 110% of rated frequency and would be connected to block tripping when it is picked up and to permit tripping when it resets.

When two or more machines are tied together at machine voltage level, including cross-compound units, any undervoltage unit supervising loss-of-field protection should be set higher or have its contacts shorted, because the voltage regulator and excitation system of the good machine(s) will maintain the voltage.

On small generators, loss of field may be detected by sensing the magnitude of field current, or by a power relay connected to sense var flow into the generator or by sensing power factor angle in excess of some angle, such as 30° underexcited. These devices tend to be less secure than the distance relay approach and therefore are often used just to sound an alarm.

4.5.1.4 Tripping mode

The loss-of-field protection is normally connected to trip the main generator breaker(s) and the field breaker and transfer unit auxiliaries. The field breaker is tripped to minimize damage to the rotor field in case the loss of field is due to a rotor field short circuit or a slip ring flashover. With this approach, if the loss of field were due to some condition that could be easily remedied, a tandem compound generator could be quickly resynchronized to the system.

This approach may not be applicable with once-through boilers, with cross-compound units, or those units that cannot transfer sufficient auxiliary loads to maintain the boiler and fuel systems. In these cases, the turbine stop valves would also be tripped. Cross-compound units with directly interconnected stator circuits may be resynchronized with the system only if the units are in synchronism with each other. If the units are out of synchronism, normal starting procedures should be used to return the units to the line. However, recent developments in the industry have established that it may be possible to resynchronize some cross-compound generators after an accidental trip without returning the two generators to turning gear speed. *This procedure should be established only after very careful consideration with the manufacturer. See IEEE Std 502 for further details on tripping.*

4.5.2 Unbalanced currents

There are a number of system conditions that may cause unbalanced three-phase currents in a generator. The most common causes are system asymmetries (untransposed lines), unbalanced loads, unbalanced system faults, and open phases. These system conditions produce negative-phase-sequence components of current that induce a double-frequency current in the surface of the rotor, the retaining rings, the slot wedges, and to a smaller degree, in the field winding. These rotor currents may cause high and possibly dangerous temperatures in a very short time.

The ability of a generator to accommodate unbalanced currents is specified by IEEE Std C50.12, IEEE Std C50.13, and IEC 60034-1 in terms of negative-sequence current (I_2). This guide specifies the continuous I_2 capability of a generator and the short time capability of a generator, specified in terms $I_2{}^2t = K$, as shown in Figure 4-39 (curve drawn using data from IEEE Std C50.13).

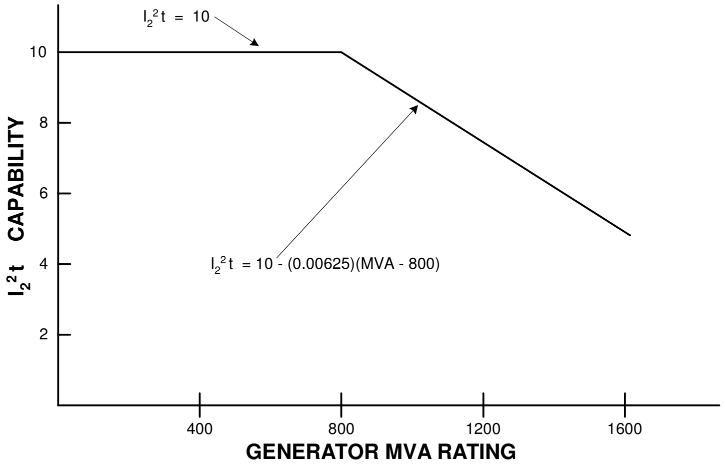

Figure 4-39—Continuous and short time unbalanced current capability of generators

A generator shall be capable of withstanding, without damage, the effects of a continuous current unbalance corresponding to a negative-sequence current I_2 of the following values, providing the rated kVA is not exceeded and the maximum current does not exceed 105% of rated current in any phase. (Negative-sequence current is expressed as a percentage of rated stator current).

Type of generator	**Permissible I_2 (percent)**
Salient pole	10
With connected amortisseur windings	10
With non-connected amortisseur windings	5
Cylindrical rotor	
Indirectly cooled	10
Directly cooled—Up to 350 MVA	8
—351 MVA to 1250 MVA	8–(MVA–350)/300
—1251 MVA to 1600 MVA	5

These values also express the negative-sequence current capability at reduced generator kVA capabilities.

Unbalanced fault negative-sequence current capability is expressed in per unit of rated current and time in seconds.

Type of generator	Permissible I_2^2t
Salient pole generator	40
Synchronous condenser	30
Cylindrical rotor generators	
Indirectly cooled	30
Directly cooled (0 MVA to 800 MVA)	10
Directly cooled (801 MVA–1600 MVA)	See Figure 4-39.

4.5.2.1 Protection

It is common practice to provide protection for the generator for external unbalanced conditions that might damage the machine. This protection consists of a time-overcurrent relay that is responsive to negative-sequence current as illustrated in Figure 4-40. Two types of relays are available for this protection: an electromechanical time-overcurrent relay with an extremely inverse characteristic and a static or a digital relay with a time-overcurrent characteristic that matches the $I_2^2t = K$ capability curves for generators.

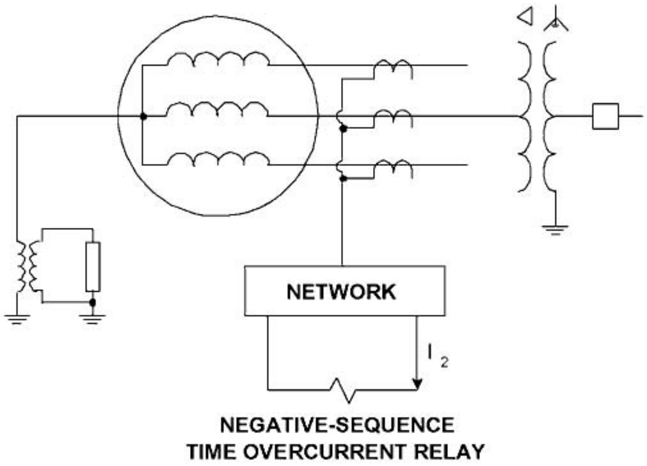

Figure 4-40—Unbalanced current protection

The electromechanical relay was designed primarily to provide machine protection for uncleared unbalanced system faults. The negative-sequence current pickup of this unit is generally 0.6 pu of rated full-load current and hence may not detect open conductors and/or severe unbalanced load conditions. Typical characteristics for this relay are shown in Figure 4-41a.

The static relays and digital multifunction protection systems are generally more sensitive and are capable of detecting and tripping for negative-sequence currents down to the continuous capability of a generator. Typical characteristics for this type of relay are shown in Figure 4-41b. Its reset characteristic typically approximates the machine cooling following an intermittent current unbalance condition.

Some relays may be provided with sensitive alarm units (I_2 pickup range 0.03 pu to 0.20 pu) that may be used to forewarn an operator when machine continuous capability is exceeded. In digital relays and some types of static relays, a meter may be provided to indicate the I_2 level in a machine.

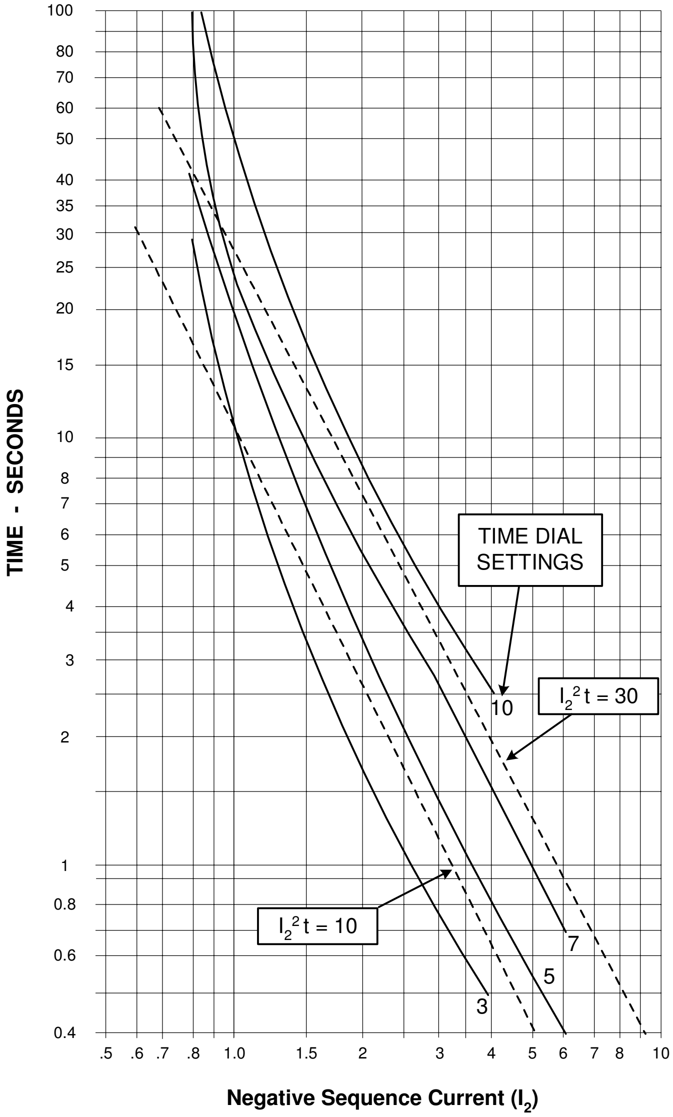

Figure 4-41a—Typical time-overcurrent curves for an electromechanical negative-sequence relay

4.5.2.2 Tripping mode

The negative-sequence relay is connected to trip the main generator breaker(s). This is the preferred tripping if the machine auxiliaries permit operation under this condition because this approach allows quick resynchronization of the unit after the unbalanced conditions have been eliminated. If the machine auxiliaries do not permit operation of the machine with this tripping, then the negative-sequence relay should also trip the machine prime mover, the field, and transfer the auxiliaries. See the cautionary advice in 4.5.1.4.

4.5.3 Loss of synchronism

As machine sizes have increased, generator per unit reactances have increased and inertia constants have decreased. The culmination of these factors has resulted in reduced critical clearing times required to isolate a system fault near a generating plant before the generator loses synchronism with the power system. In addition to prolonged fault clearing times, generator loss of synchronism may also be caused by low system voltage, low machine excitation, high impedance between the generator and the system, or some line switching operations. When a generator loses synchronism, the resulting high peak currents and off-frequency operation cause winding stresses, pulsating torques, and mechanical resonances that are potentially damaging to the generator and turbine generator shaft. To minimize the possibility of damage, the generator should be tripped without delay, preferably during the first half slip cycle of a loss-of-synchronism condition.

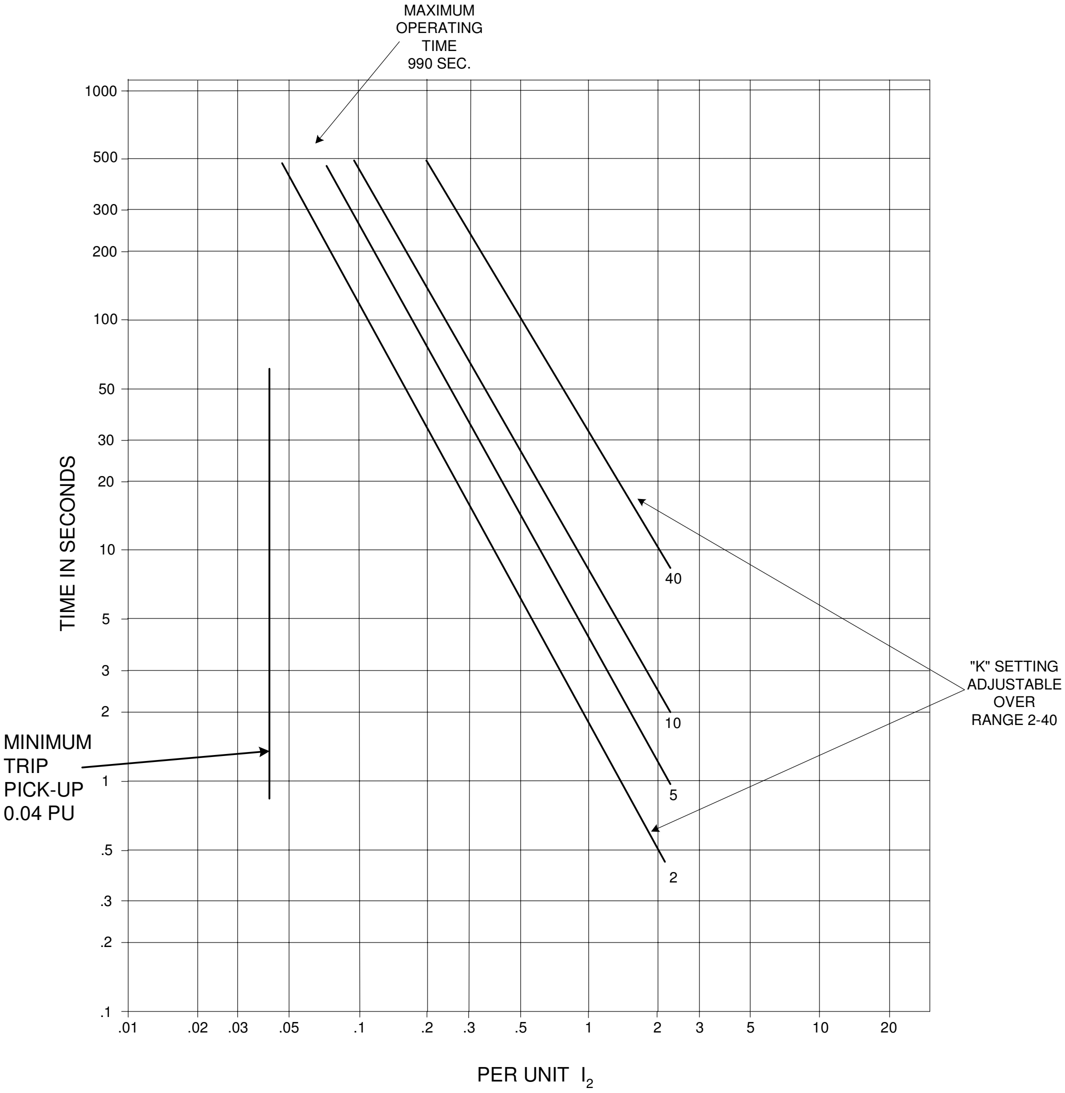

Figure 4-41b—Characteristics of a static negative-sequence time-overcurrent relay

4.5.3.1 Protection

The protection normally applied in the generator zone, such as differential relaying, time-delay system backup, etc., will not detect loss of synchronism. The loss-of-excitation relay may provide some degree of protection but cannot be relied on to detect generator loss of synchronism under all system conditions. Therefore, if during a loss of synchronism the electrical center is located in the region from the high-voltage terminals of the GSU transformer down into the generator, separate out-of-step relaying should be provided to protect the machine. This is generally required for larger machines that are connected to EHV systems. On large machines the swing travels through either the generator or the main transformer.

This protection may also be required even if the electrical center is out in the system and the system relaying is slow or cannot detect a loss of synchronism. Transmission line pilot-wire relaying, current-differential relaying, or phase comparison relaying will not detect a loss of synchronism. For generators connected to lower voltage systems, overcurrent relaying may not be sensitive enough to operate on loss of synchronism.

One relaying approach for detecting a loss-of-synchronism condition is to analyze the variation in apparent impedance as viewed at the terminals of system elements. It has been shown that during a loss of synchronism between two system areas or between a generator and a system, the apparent impedance as viewed at a line or generator terminals will vary as a function of the generator and system impedance, the system voltages, and the angular separation between the systems.

For example, Figure 4-42 shows for a generator loss of synchronism the variation of impedance as viewed from the machine terminals for three different system impedances. The point P is the initial load impedance. Point S is the short-circuit impedance at fault application and point R at the instant of clearing. In all cases, instability was caused by the prolonged clearing of a nearby three-phase fault on the high-voltage side of the generator unit transformer. The variation of impedance or impedance loci are approximately circular characteristics that move in a counterclockwise direction. For a system impedance of 0.05 pu, the electrical center is inside the machine: for a Z_{sys} = 0.2 pu the electrical center is at the machine terminals, while for a Z_{sys} = 0.4 pu the electrical center is in the unit transformer.

This variation in impedance may be readily detected by impedance relaying, and in most instances, the generator may be separated before the completion of one slip cycle. For specific cases, stability studies may determine the loci of an unstable swing so that the best selection of an out-of-step relay or relay scheme may be made.

4.5.3.2 Single-blinder scheme

A number of different schemes have been used for detecting generator instability. A basic scheme used for generator loss-of-synchronism protection is the single-blinder scheme. This scheme is illustrated in Figure 4-43 and explained in Gouda et al. [B121]. The blinder units are supervised by a mho unit that is set to permit tripping for impedance swings that appear in the generator or unit transformer and a limited portion of the system, but to prevent operation of the scheme on stable swings that pass through both blinders and outside the mho characteristic. The blinders, the mho unit, and associated logic evaluate the progressive change in impedance as it moves from M to P during a loss of synchronism and initiate tripping when the angle between the generator and system voltages is 90° or less. Tripping at this angle (90° or less) may be necessary to minimize duty on the circuit breaker(s).

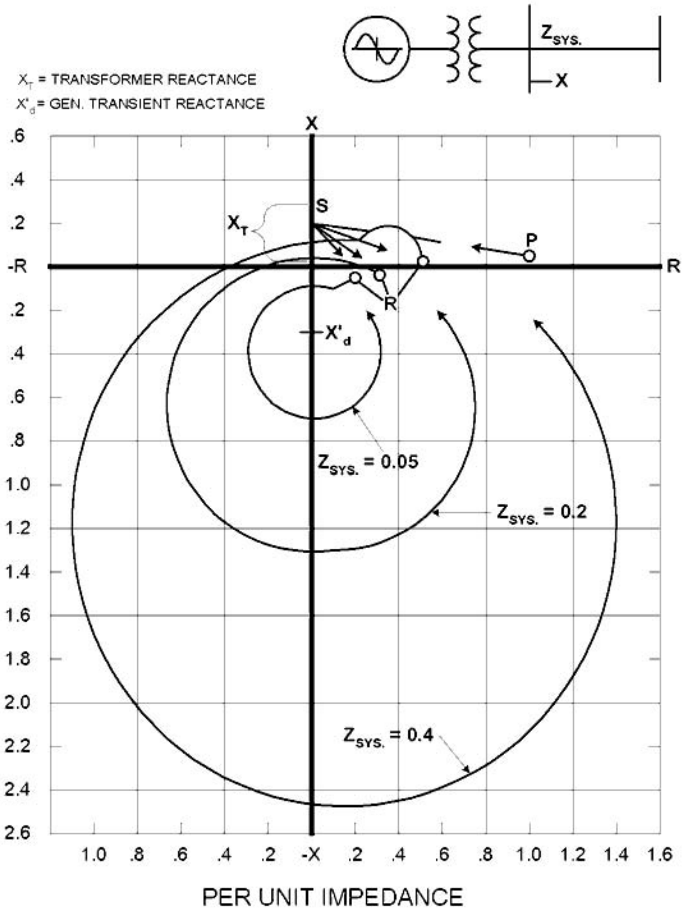

Figure 4-42—Loss of synchronizing for a tandem compound generator—voltage regulator out of service

As the impedance changes from *M* to *P* during system swing, regions traversed cause blinder elements to operate and reset. As the swing progresses, element A operates, then element B operates. As the swing progresses further toward *P*, element A resets, and finally B resets. Timers and associated logic in the relay monitor the pickup and dropout of these elements. If A and B remained picked up for a certain time period, and A subsequently resets, an out-of-step condition is recognized and the relay operates. Such a scheme is used for generator out-of-step sensing because logic requires that swing ohms emerge from the side of the relay characteristic opposite to that which it entered. That is, there should be reversal of the power flow as viewed from the machine terminals, and the reversal should occur during a high current. These two conditions indicate the machine is out-of-step with the system.

It should be noted in Figure 4-43 that the generator out-of-step relaying scheme may detect swings that pass through lines leaving the generating station. If the line relays are not blocked by out-of-step detection schemes, they will operate before the generator out-of-step relaying scheme and could separate the generating plant from the system. The scheme illustrated in Figure 4-43 is shown connected at the generator terminals. This scheme may also be applied at the high-voltage side of the transformer terminals.

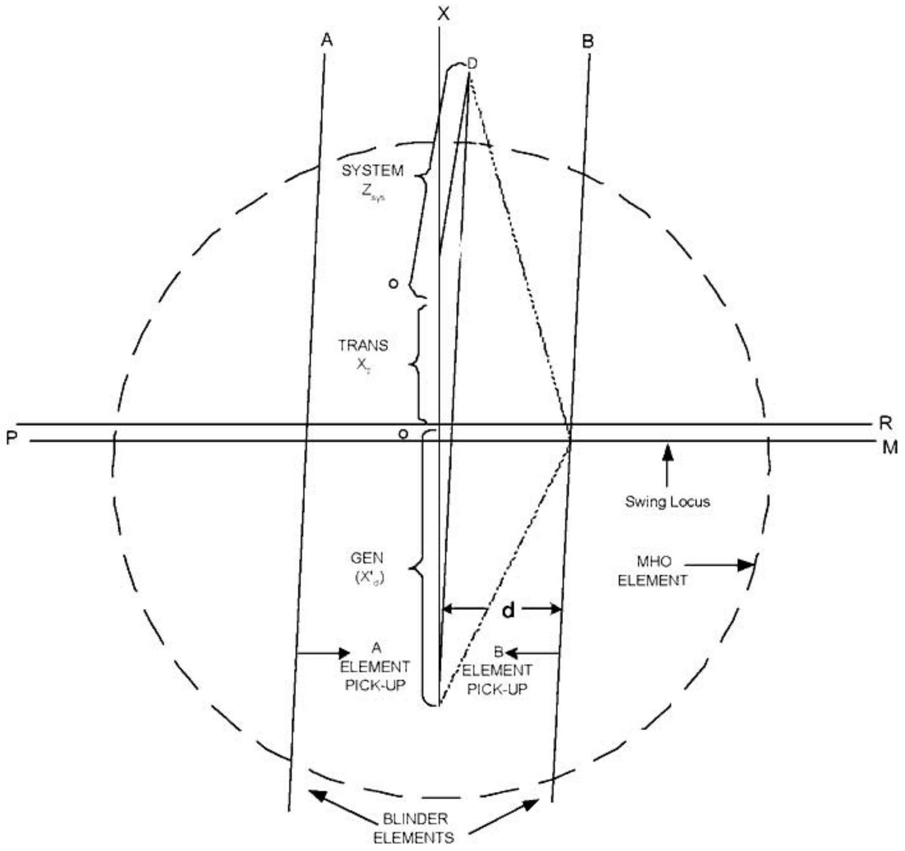

Figure 4-43—Single-blinder scheme

4.5.3.3 Double-lens or double-blinder schemes

The double-lens and double-blinder systems perform in a manner similar to the systems previously described. The supervisory mho element is included in the double-blinder system to obtain the same security features covered in the discussion on the single-blinder scheme. Referring to Figure 4-44 and Figure 4-45, the outer blinder element (LOB or 21BO) operates when the swing impedance enters its characteristics, as at F. Note that in the double-blinder scheme the mho element will pick-up before the outer blinder element. If the swing remains between the outer and inner blinder element (LT or 21BI) characteristics for longer than a preset time, it is recognized as an out-of-step condition in the logic circuitry. When the swing impedance enters the inner element characteristics, a portion of the logic circuitry is sealed in after a short time delay. Then as the swing impedance leaves the inner element characteristic, its traverse time should exceed a preset interval before it reaches the outer characteristic.

Tripping does not occur until the swing impedance passes out of the outer characteristic, or for the double-blinder scheme, until the reset of the supervisory mho element, depending upon the particular logic being used. The preset traverse time of the swing impedance between the inner and outer elements is provided to prevent the trip logic being set up for sequential clearing of a fault. In the case of a fault, the inner and outer elements reset practically simultaneously and no incorrect tripping results.

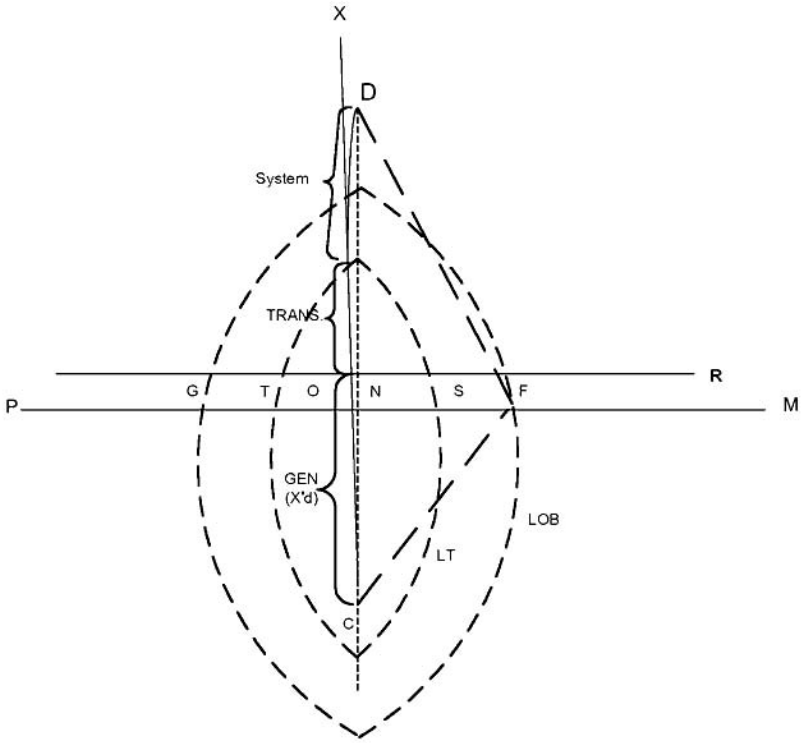

Figure 4-44—Double-lens scheme

The swing angle DFC is controlled by the settings to limit the voltage across the opening poles of the breakers. Once the swing has been detected and the impedance has entered the inner characteristic, the swing may now leave the inner and outer characteristics in either direction and tripping will take place. Therefore, the setting of the inner element should be such that it will respond only to swings from which the system cannot recover. This restriction does not apply to the single-blinder scheme because the logic requires that the apparent ohms enter the inner area from one direction and exit toward the opposite.

The majority of users do not apply specific backup for loss-of-synchronism relaying; however, some rely on the loss-of-field relay to provide a degree of backup and/or a distance relay applied on the high-voltage side of the unit transformer looking into the unit transformer and generator with no offset and tripping with no intentional time delay, other than that required to provide security against misoperation on stable swings.

4.5.3.4 Tripping mode

This protection may be connected to trip only the main generator breaker(s) and thereby isolate the generator with its auxiliaries if the unit has full-load rejection capabilities. In this way, when system conditions have stabilized, the unit may be readily resynchronized to the system. If the unit does not have full-load rejection capability, this protection should be converted to trip and shut down the generator and the prime mover. See the cautionary advice in 4.5.1.4.

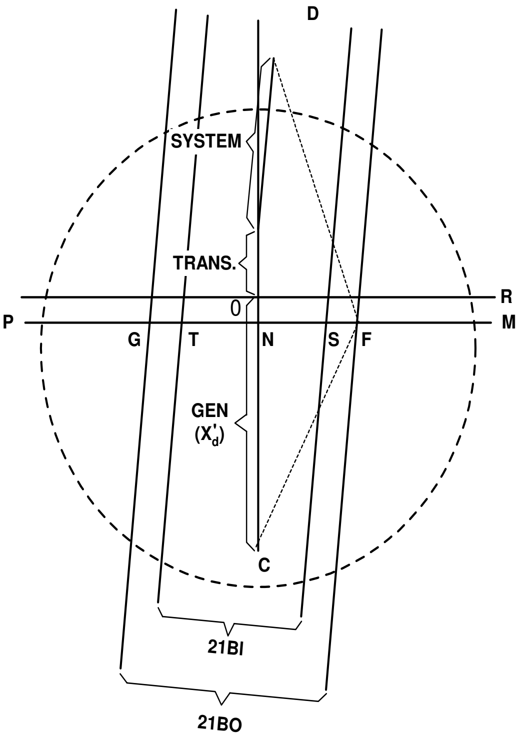

Figure 4-45—Double-blinder scheme

4.5.4 Overexcitation

IEEE Std C50.12, 4.1.5; IEEE Std C50.13, 4.17; and IEEE Std 67 state that generators shall operate successfully at rated kilovolt-amperes (kVA), frequency, and power factor at any voltage not more than 5% above or below rated voltage. Deviations in frequency, power factor, and voltages outside these limits may cause thermal distress unless the generator is specifically designed for such conditions. Overexcitation is one such deviation for which monitoring and protection schemes may be provided.

Overexcitation of a generator or any transformers connected to the generator terminals will occur whenever the ratio of the voltage to frequency (V/Hz) applied to the terminals of the equipment exceeds 105% (generator base) for a generator; and 105% (transformer base) at full load, 0.8 pf or 110% at no load at the secondary terminals for a transformer. The secondary is defined to be the output terminals of the transformer. When these volts/hertz (V/Hz) ratios are exceeded, saturation of the magnetic core of the generator or connected transformers may occur, and stray flux may be induced in nonlaminated components that are not designed to carry flux. Excessive flux may also cause excessive eddy currents in the generator laminations that result in excessive voltages between laminations. This may cause severe overheating in the generator or transformer and eventual breakdown in insulation. The field current in the generator could also be excessive.

Manufacturers should be consulted for recommendations on maximum V/Hz withstand to avoid this latter condition. A typical tripping recommendation is to trip the unit if V/Hz exceeds 118% for 2 s to 6 s, as shown in Figure 4-46.

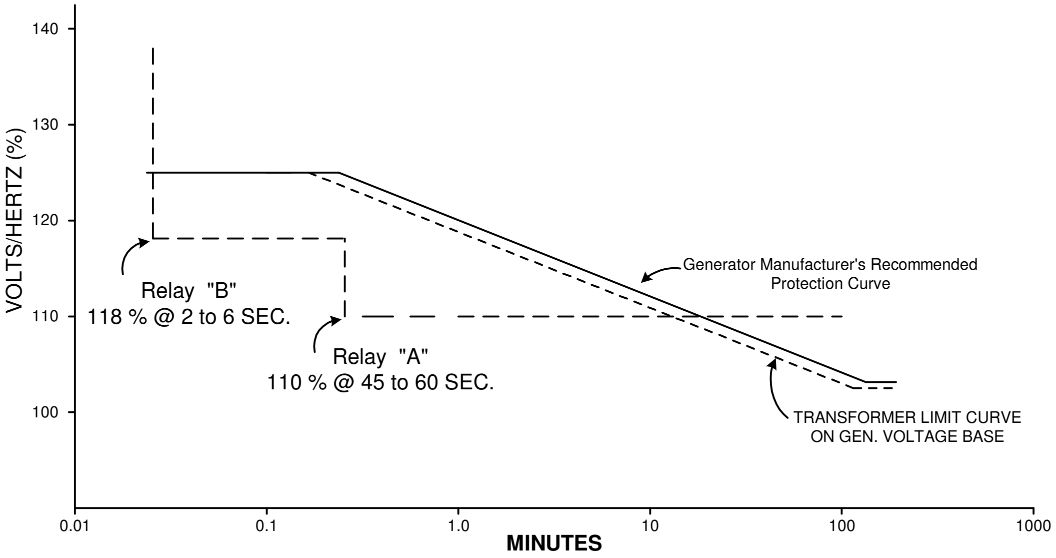

Figure 4-46—Example of setting for dual fixed time V/Hz relays

One of the primary causes of excessive V/Hz on generators and transformers is operation of the unit under regulator control at reduced frequencies during start-up and shutdown. With the regulator maintaining rated voltage while the unit is at 95% or lower speed, the V/Hz at the terminals of the machine will be 105% or greater and damage may occur to the generator and/or connected transformers. Generator rotor prewarming is an example of operating an unloaded machine at reduced terminal voltage and frequency. CTGs with converter starting may be subjected to very low frequencies (such as 2 Hz) during starting.

Overexcitation may also occur during complete load rejection that leaves transmission lines connected to a generating station. Under this condition, the V/Hz may exceed 125%. With the excitation control in service, the overexcitation will generally be reduced to safe limits in a few seconds. With the excitation control out of service, the overexcitation may be sustained and damage may occur to the generator and/or transformers.

Failures in the excitation system or loss of signal voltage to the excitation control may also cause overexcitation.

Industry standards do not at present specify definite short time capabilities for generators and transformers. However, manufacturers will generally provide overexcitation capability limits for this equipment. There are several methods of preventing an overexcitation condition.

4.5.4.1 V/Hz limiter in excitation control

The limiter will limit the output of the machine to a set maximum V/Hz no matter what the speed of the unit. This limiter functions only in the automatic control mode. To provide protection when the unit is under manual control, the limiter may have a relay signal output that will activate any additional protective circuits to trip the generator field. The relay circuit is functional whether the excitation control is in or out of service.

With or without a V/Hz limiter in the excitation control, it is common practice to provide separate V/Hz relaying to protect the station transformers and the generator, when the excitation control is out of service.

4.5.4.2 Single or dual fixed time V/Hz relays

Several forms of protection are available and may be provided with the generating unit. One form uses a single V/Hz relay set at 110% of normal, which alarms and trips in 6 s. A second form of fixed time protection uses two relays to better match the generating unit V/Hz capability.

The first relay B is set at 118% to120% V/Hz and energizes an alarm and a timer set to trip in 2 s to 6 s. The second relay A is set at 110% V/Hz and energizes an alarm and a timer set to trip just below the permissible generator and/or transformer operating time at the V/Hz setting of the first relay (for example, 118%). This is typically 45 s to 60 s. Refer to Figure 4-46 for a dual level V/Hz setting example.

Typical V/Hz relays are single-phase devices that are connected to the generator VTs. Since a VT fuse failure may give an incorrect voltage indication, complete and redundant protection may be provided by connecting one set of relays to VTs that supply the voltage regulator and connecting a second set of relays to a different set of VTs such as those used for metering or relaying functions. Strong consideration should be given to applying two V/Hz relays connected to separate VTs on large or critical generators.

4.5.4.3 Inverse time V/Hz relay

A V/Hz relay with an inverse characteristic may be applied to protect a generator and/or transformer from an excessive level of V/Hz. A minimum operating level of V/Hz and time delay may usually be set to provide a close match to the combined generator-transformer V/Hz characteristics. The manufacturers' V/Hz limitations should be obtained if possible and used to determine the combined characteristic.

One version of the V/Hz relay has an inverse time characteristic and a separate definite time delay unit. This unit may be connected to trip or alarm and extend the ability of the relay characteristic to match the V/Hz characteristic of a generator-transformer combination. Refer to Figure 4-47 for a setting example of a V/Hz relay with an inverse characteristic. When the transformer rated voltage is equal to the generator rated voltage, the previous schemes supplied with the generator may protect both the generator and the transformer. In many cases, however, the rated transformer voltage is lower than the rated generator voltage and may result in a more limiting V/Hz characteristic. Therefore, both the generator and transformer V/Hz characteristics should be determined with protection applied for the most restrictive curve.

To maximize the probability of a machine remaining online after a system disturbance, an excitation system that boosts and operates with a set margin along the inverse time protection characteristic should be considered.

Another factor that should be considered during an overexcitation condition is the possible unnecessary operation of the transformer differential relays in a unit generator-transformer arrangement. This is undesirable since it would falsely indicate a fault in the transformer. When the unit transformer is delta-connected on the low-voltage side, an overexcitation condition may produce exciting currents that contain a large 60 Hz component with very little odd harmonics. In this instance, the 60 Hz component of exciting current may be above relay pickup, and the magnitudes of the harmonics may not be sufficient to provide adequate restraint.

Three approaches have been used to prevent such operations. One approach uses a V/Hz relay to block tripping of or to desensitize the transformer differential relay when the V/Hz exceeds a specified level.

The second approach uses a modified differential scheme that extracts and utilizes a third harmonic exciting current from the transformer delta winding to restrain the relay from operating during an overexcitation condition. It should be recognized that the first two approaches somewhat degrade the differential protection.

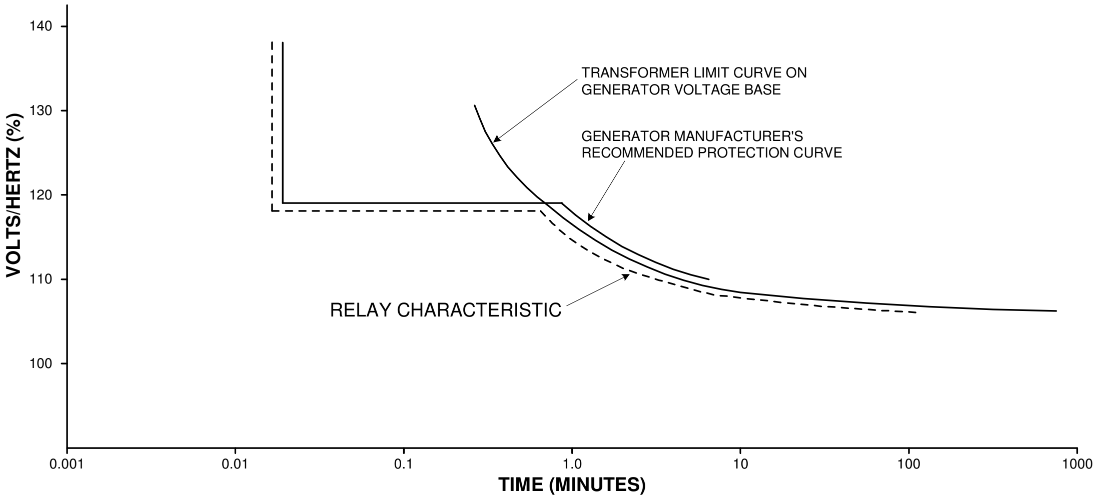

Figure 4-47—Example of setting for inverse-time V/Hz relay with fixed time unit

The third approach utilizes a differential relay that restrains on the fifth harmonic as well as the second harmonic. The fifth is the lowest harmonic flowing from the delta windings under balanced conditions.

4.5.4.4 Off-line overexcitation protection using field current

When a generator is operating off-line, rated output voltage is achieved with a much smaller value of field current (I_{FNL}) or rated field current at no load than when connected to the system and operating at full load (I_{FFL}) or rated field current at full load. At no load, the magnetic flux density is proportional to the applied voltage and the machine is operating in the knee of its saturation curve. Increasing voltage above the machine rated voltage (typically 105%) may quickly cause excessive flux densities and heating in the stator core areas. Damage may occur rather quickly as voltage levels approach and exceed 110% of the machine rated voltage. Unit connected step-up_transformers and auxiliary transformers are also subject to damage. While V/Hz limiters and/or relays should provide protection for this condition, it is possible that these devices may not be active. This may be due to failure to reconnect VTs prior to start-up, misalignment of or damage to the VT primary or secondary connections, open or omitted VT fuses, or VT circuit or component problems that result in incorrect voltmeter readings (lower than actual voltage) observed by operators. Where two sets of VTs are applied, voltage balance detection would not detect a condition where both sets of VTs or VT fuses have been left disconnected. Because severe iron damage may occur so rapidly, supplemental overexcitation protection for these possible conditions should be considered.

A dc relay may be connected across a field shunt to check when the machine field current has reached a given value. This shunt will be located in the exciter field circuit on machines with brushless excitation systems. During start-up or shutdown, this supplemental off-line protection may help prevent an overexcitation condition if something is wrong with the potential circuits or generator voltmeter and the V/Hz relays are unable to function. This relay is designed to be active only when the unit is off-line and is set to operate when field current exceeds I_{FNL} by a certain value. The scheme may be set to alarm, initiate automatic field run back, and/or trip the generator excitation system or field breaker. A short time delay is usually applied to prevent nuisance alarms or tripping. A typical scheme will employ an alarm relay set to operate at a field current value slightly above that corresponding to 105% rated generator voltage (106% to 107%) and a tripping relay set to operate at a field current that corresponds to 110% rated generator voltage. Measurement of shunt voltage at rated voltage and values up to 105% rated voltage under start-up and shutdown conditions is a practical method to optimize the set points for good protection and preventing nuisance alarms and trips.

While this protection may be added to older generator protection schemes using dc millivolt relays connected to a shunt as previously described, an off-line overexcitation protection relay or limiter employing field current measurement (using a shunt or shunt/transducer combination) is typically available as a standard feature in modern excitation systems.

4.5.4.5 Tripping mode

This protection is generally connected to trip the main generator breaker(s) and the field breaker(s) and transfer auxiliaries if necessary. If the unit is off-line, it is only required to trip the field breaker. Again, this permits fast resynchronization of the generator if the overexcitation condition may be remedied quickly. When a unit is off-line, alarm and inhibit circuits may be required to prevent an operator from exceeding safe levels of excitation when preparing a unit for synchronizing. See the cautionary note in 4.5.1.4.

4.5.5 Motoring

Motoring of a generator occurs when the energy supply to the prime mover is cut off while the generator is still online. When this occurs, the generator will act as a synchronous motor and drive the prime mover. While this condition is defined as generator motoring, the primary concern is the protection of the prime mover that may be damaged during a motoring condition.

In sequential tripping schemes for steam turbine generators, a deliberate motoring period is included in the control logic to prevent potential overspeeding of the unit (see also 7.2.3.4). While some of the devices used in the control logic for sequential tripping schemes are the same as those used in antimotoring protection, the two functions should not be confused. Antimotoring protection should provide backup protection for this control logic as well as for other possible motoring conditions that would not be detected by the sequential tripping control logic (such as inadvertent closure of governor valves or high system frequency conditions).

Intentional motoring conditions may be permitted on both gas turbine and hydro applications, where the process is used to accelerate the rotor during starting conditions, or the installation is operated in a pump/storage mode.

4.5.5.1 General considerations

Motoring causes many undesirable conditions. For example, in a steam turbine, the rotation of the turbine rotor and blades in a steam environment causes idling or windage losses. Since windage loss is a function of the diameter of rotor disc and blade length, this loss will usually be greatest in the exhaust end of the turbine. Windage loss is also directly proportional to the density of enclosing steam. Thus, any situation in which the steam density is high causes damaging windage losses. For example, if vacuum is lost on the unit, the density of the exhaust steam will increase and cause the windage losses to be many times greater than normal. Also, when high-density steam is entrapped between the throttle valve and the interceptor valve in reheat units, the windage losses in the high-pressure turbine are very high.

Windage loss energy is dissipated as heat. The steam flow through a turbine has a two-fold purpose: to give up energy to cause rotation of the rotor and to carry away the heat of the turbine parts. Since there is no steam flow through the turbine during motoring, the heat of the windage losses is not carried away and the turbine is heated. Even in the situation where the unit has been synchronized but no load has been applied and enough steam is flowing through the unit to supply the losses, the ventilating steam flow may not be sufficient to carry away all of the heat generated by the losses. Although the generator is not motoring under this condition, the problems caused in the turbine are the same and protection should be provided.

Since the temperature of the turbine parts is controlled by the steam flow, various parts will cool or heat at abnormal, uncontrolled rates during motoring. This may cause severe thermal stresses in the turbine parts. Another problem resulting from this temperature change would be unequal contraction or expansion of the turbine parts. This could cause a rub between rotating and stationary parts. Since a rub will generate heat, the problem is made more severe (as with windage losses) by the lack of ventilation steam flow to carry the heat away.

There is a maximum permissible time that a steam turbine may be operated in a motoring condition and this time is generally a function of the rated speed of the unit. This data may readily be obtained from the manufacturer for a particular steam turbine unit.

Windage loss may also result in additional motoring difficulties in other types of prime movers. Gas turbines, for example, may have gear problems when being driven from the generator end. With hydro-turbines, motoring may cause cavitation of the blades on low water flow. If hydro units are to operate as synchronous condensers, the unit will be motoring. This should be recognized in any motoring protection. With diesel engine generating units, there is the additional danger of explosion and fire from unburned fuel. Motoring protection should therefore be provided for all generating units except units designed to operate as synchronous condensers, such as hydro units, and may be detected by various means.

4.5.5.2 General cautions

Since rotational losses are relatively small, destructive overspeeds may occur if the unit is disconnected from the power system unless the prime-mover power is shut off. Steam turbines are particularly vulnerable, given the complexity of the turbine steam flow paths. Failure of steam valves to close completely due to warpage or mechanical sticking or backflow from steam extraction lines could provide sufficient steam flow into the turbine to overspeed the unit. For this reason, antimotoring protection by the detection of electrical reverse power flow provides the highest assurance against excessive overspeed. If other devices are used for protection, consideration should be given to potential overspeeding of the unit.

Hydro-turbine-driven units, in contrast, are frequently designed to withstand severe overspeed conditions.

4.5.5.3 Reverse power relay

From a system standpoint, motoring is defined as the flow of real power into the generator acting as a motor. With current in the field winding, the generator will remain in synchronism with the system and act as a synchronous motor. If the field breaker is opened, the generator will act as an induction motor. A power relay set to look into the machine is therefore used on most units. The sensitivity and setting of the relay is dependent upon the type of prime mover involved. The power required to motor is a function of the load and mechanical losses of the idling prime mover and generator.

In gas turbines, for example, the large compressor load represents a substantial power requirement from the system, up to 50% of the nameplate rating of the unit, so the sensitivity of the reverse power relay is not critical. A diesel engine with no cylinders firing represents a load of up to 25% of rating, so again there is no particular sensitivity problem. The diesel manufacturer should be consulted for reverse power ratings.

With hydro-turbines, when the blades are under the tail-race water level, the reverse power is high. When the blades are above the tail-race level, however, the reverse power is low, between 0.2% to 2.0% of rated, and a sensitive reverse power relay may be required.

Steam turbines operating under full vacuum and zero steam input require about 0.5% to 3% of rating to motor. This may be detected by a sensitive reverse power relay. Some schemes use low forward power instead of reverse power relay. This is due to the fact that some steam machines may not motor when the valves are fully closed.

There may be operating conditions where a reverse power relay will not be able to detect a condition detrimental to the prime mover. Specifically, with many excitation control systems, sudden loss of prime mover will not result in a significant reduction in the var output of the machine. Accurate measurement of very low power levels at low power factors may not be possible for some reverse power relays. If automatic reduction of generator reactive power during these conditions cannot be accomplished, alternate means of protection or alerting of operators should be used.

Reverse power relays are always applied with time delay. The time delay selected should coordinate with allowable turbine motoring times. Up to 60 s time delay (typically 30 s for steam turbines) may be used to prevent operation during power swings caused by system disturbances or when synchronizing the machine to the system.

4.5.5.4 Exhaust hood temperature

Since the prime cause of distress in a motoring steam turbine is the temperature rise due to the windage losses, temperature sensing devices may be used for protection. Since windage loss is generally most severe in the exhaust end of the turbine, a temperature sensing device located in the exhaust hood is often used as auxiliary protection. This device is used to alarm the operator for this motoring condition.

This device should not be used as primary protection, since the temperatures measured will vary with the location on the exhaust end of the turbine. Placement of the detector is important. Also, the reliability of existing detectors is questionable. Some other form of protection should therefore be used as primary protection.

4.5.5.5 Turbine steam flow

Steam flow equal to or greater than synchronous-speed (no-load steam flow) is an indication that the unit is not being motored. The steam flow, even at this very low percentage of rated steam flow, may be determined by measuring the pressure drop across the high-pressure turbine element. Use of a differential pressure switch across this high-pressure element is a method of detecting a motoring condition. It functions independently of the type of control system, whether hydraulic or electrohydraulic. This device is not susceptible to the potential problems associated with lower power factor operation as are reverse power relays. Although these pressure switches are generally reliable, mechanical malfunctioning of the switch may occur.

4.5.5.6 Tripping mode

Primary motoring protection is provided by reverse power relays for all types of units. The relay is generally connected to trip the main generator breaker(s) and field breaker(s), transfer the auxiliaries, and provide a trip signal to the prime mover.

On steam turbine generators, differential steam pressure across the high-pressure turbine element may also be used as primary protection. Steam turbine exhaust hood temperature may be used as an alarm.

A manual trip bypass may be necessary to allow operator intervention in the event of the lack of operation of the primary motoring protection.

4.5.6 Overvoltage

Generator overvoltage may occur without necessarily exceeding the V/Hz limits of the machine. In general, this is a problem associated with hydrogenerators, where upon load rejection, the overspeed may exceed 200% of normal. Under this condition on a V/Hz basis, the overexcitation may not be excessive but the sustained voltage magnitude may be above permissible limits. Generator V/Hz relays will not detect this overvoltage condition and hence a separate overvoltage protection is required. In general, this is not a problem with steam and gas turbine generators because of the rapid response of the speed-control system and voltage regulators.

4.5.6.1 Protection

Protection for generator overvoltage is provided with a frequency-compensated (or frequency-insensitive) overvoltage relay. The relay should have both an instantaneous unit and a time-delay unit with an inverse time characteristic. The instantaneous unit is generally set to pick up at 130% to 150% voltage while the inverse time unit is set to pick up at about 110% of normal voltage. Two definite time-delay relays can also be applied.

4.5.6.2 Tripping mode

The protection is generally connected to trip the main generator breaker(s) and field breaker(s), and transfer the auxiliaries. See the cautionary advice in 4.5.1.4.

4.5.7 Undervoltage

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.

4.5.7.1 Protection

Undervoltage condition is detected by an undervoltage relay with definite time or inverse time delay.

4.5.7.2 Tripping mode

The undervoltage relay is generally connected to alarm and not trip the unit, so that the operator can take appropriate action to remedy the undervoltage condition (if possible).

4.5.8 Abnormal frequencies

The operation of generators at abnormal frequencies (either overfrequency or underfrequency) can result from load rejection or mismatch between system loading and generation. Full- or partial-load rejection may be caused by clearing of system faults or by overshedding of load during a major system disturbance. Load rejection will cause the generator to overspeed and operate at some frequency above normal. In general, the overfrequency condition does not pose serious problems since operator and/or control action may be used to quickly restore generator speed and frequency to normal without the need for tripping the generator.

Mismatch between load and generation may be caused by a variety of system disturbances and/or operating conditions. However, of primary concern is the system disturbance caused by a major loss of generation that produces system separation and severe overloading on the remaining system generators. Under this condition, the system frequency will decay and the generators may be subjected to prolonged operation at reduced frequency. While load shedding schemes are designed to arrest the frequency decay and to restore frequency to normal during such disturbances, it is possible that undershedding of load may occur. This may cause an extremely slow return of frequency to normal or the bottoming out of system frequency at some level below normal. In either case, there exists the possibility of operation at reduced frequency for sufficient time to damage steam or gas turbine generators. In general, underfrequency operation of a turbine generator is more critical than overfrequency operation since the operator does not have the option of control action. Therefore, it is usually recommended that some form of underfrequency protection be provided for steam and gas turbine generators.

4.5.8.1 Abnormal frequency capabilities of turbine generators

Both the generator and the turbine are limited in the degree of abnormal frequency operation that may be tolerated.

At reduced frequencies, there will be a reduction in the output capability of a generator. The reduction in capability is generally in some proportion to the reduction in frequency. There are no standards that specify generator capability at reduced frequencies, but this information is generally available from the generator manufacturer. The reduction in output capability coupled with possible overloading of the generator during a system disturbance may result in thermal damage to the generator if its short time thermal capability is exceeded. This possibility should be recognized and protection provided as discussed in 4.1 of this guide.

The turbine is usually considered to be more restrictive than the generator at reduced frequencies because of possible mechanical resonances in the many stages of turbine blades. The longer turbine blades usually associated with the low-pressure turbine are the ones most susceptible to being damaged by prolonged abnormal frequency operation. Departure from rated speed will bring stimulus frequencies closer to one or more of the natural frequencies of the various blades, and there will be an increase in vibratory stresses. As vibratory stresses increase, damage is accumulated that may lead to cracking of some parts of the blade structure, most likely the tie wires or blade covers. Tie wire and blade cover cracks are not catastrophic failures but they change the vibration behavior of the blade assembly so that it is likely to have natural resonance frequencies closer to rated speed. This may produce blade fatigue during normal running conditions.

Turbine manufacturers provide time limits for abnormal frequency operation. This data is usually provided in the form of permissible operating time in a specified frequency band. There may be anywhere from one to six frequency bands specified for a turbine under load, depending upon the design and the manufacturer. The effects of abnormal frequency operation are cumulative. Hence, if a turbine is operated for 50% of the permissible time in a specified frequency band, this leaves only 50% of the permissible time left in that frequency band for the remainder of the unit’s life.

These turbine capability limitations generally apply to steam turbine generators. CTGs in general have greater capability than steam units for underfrequency operation. However, CTGs are frequently limited by combustion instability and/or sharply reduced turbine output as frequency drops. On some units, the CTG protection system will automatically runback (reduce MW output) if an attempt is made to maintain full output during underfrequency conditions because a combustion turbine may suddenly lose air flow. Loss of air flow will result in immediate unit trip following the detection of a change in axial rotor position, shaft and/or bearing vibration, loss of flame in the combustor(s), or excess temperature of the turbine. The specific underfrequency limit should be obtained from the manufacturer for each CTG. In general, there are no restrictions on hydrogenerators.

4.5.8.1.1 IEC 60034-3

If the turbine generators are designed to accommodate IEC 60034-3, then the generators are required to deliver continuously rated output at the rated power factor over the ranges of ±5% in voltage and ±2% in frequency, as shown by the shaded area in Figure 4-48.

IEC 60034-3 recommends that operation outside the shaded areas “be limited in extent, duration and frequency of occurrence.” A manufacturer could, therefore, impose severe time restrictions for the generator itself, particularly for operation below 95% of rated frequency or above the 103% of rated frequency (respectively 57 Hz or 61.8 Hz on a 60 Hz basis) and, to a lesser extent, for operation outside of the continuous range of 98% to 102% of rated frequency. Operation outside of the standard frequency range may result in accelerated aging of generator and prime-mover mechanical components due to high cycle fatigue of stationary and rotating components.

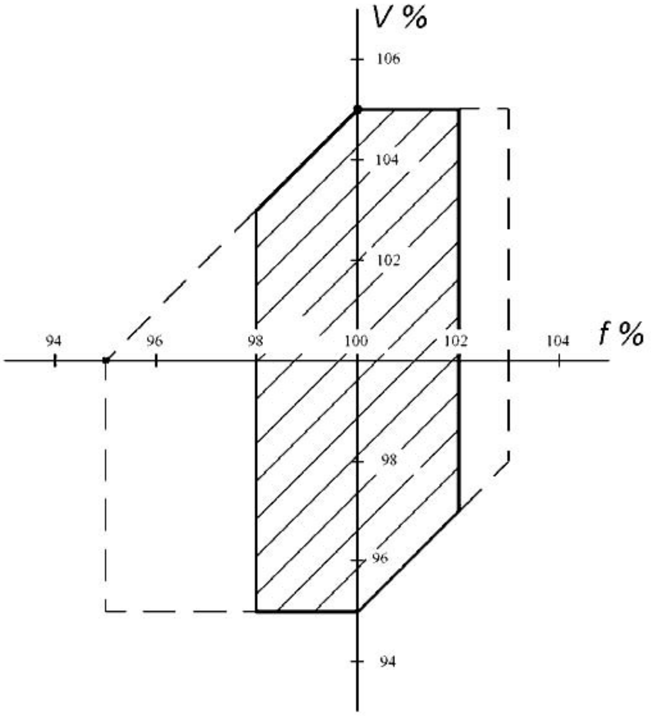

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Figure 4-48—Operation over ranges of voltages and frequency

In view of these considerations, a manufacturer may require, for the generator only, frequency operational limits in the form of time-frequency characteristics. In such a situation, the principal goal of frequency protection schemes is to return the frequency to the continuous IEC operating frequency range (98% to 102% of rated frequency) as soon as possible and to minimize operation outside of this range, both in extent and in duration, and in concert with load shedding practices.

4.5.8.2 Load-shedding based underfrequency protection

Turbines have resonant frequencies below 60 Hz. Underfrequency relays may be used to trip the machine at those specific frequencies, after a time delay, to prevent sustained operation and damage. Because of system configuration, some generators may be at risk of being in an electrical island, which could stabilize at a frequency below 60 Hz. Not all turbine generators have underfrequency tripping, particularly if the likelihood of such islanding is small, due to their position in the power system.

Automatic load shedding programs on the transmission power system provide the initial underfrequency protection for the system turbine generators. The design of these load shedding programs should be for the maximum possible overload conditions and ensure that sufficient load is shed to quickly restore system frequency to near normal. The coordination of the transmission system load shedding scheme with the individual generators is critical to maintaining the integrity of the system and should not intrude on the reliability of the electrical power system.

Specific information and characteristics of the electrical power transmission system should be studied and understood before proper system load shedding is implemented. Characteristics of the turbine generator are based on the design of the specific unit and manufacturer's recommendation and should be understood before proper application of turbine-generator underfrequency protection is implemented.

4.5.8.3 Underfrequency protection

The turbine underfrequency protection scheme may be accomplished by one or more relays. Digital or solid-state relays are preferred for their accuracy over a broad frequency range. The required number of frequency set points and their associated time delays are dependent upon the characteristics of the turbine. This relay function may be included in a multifunctional protection package.

IEEE Std C37.106™-2003 [B64] should be consulted for a more complete discussion of turbine underfrequency protection. The first step in designing an underfrequency protection scheme is determining the turbine's abnormal frequency operating characteristic. Consultation with the manufacturer should provide the initial design parameters. Modifications to the turbine as well as the known condition from turbine inspections may result in changes to either the resonant frequency or the allowable abnormal frequency operate time, or both. From this information, the number of frequency levels that require action may be identified. It should be noted that extreme frequency variations may not require underfrequency relay action as other plant equipment will force the plant to trip. Once the number of frequency steps is known, the time delay for each step should be determined. Because the allowable underfrequency operation time cannot be identified exactly, some margin should be included in the time delay. This would allow tripping of the unit prior to damage, with the opportunity to inspect the turbine at the owner's convenience during a future outage. This allows for application of underfrequency protection, even if the unit has been in operation for many years without having accumulated previous underfrequency operational data. The time-delay margins should consider the importance of the unit, the susceptibility of the system to an underfrequency event, and operating agreements with local or regional power authorities. A range of 50% to 90% of the allowable time per expected event over the blading life is reasonable. Settings of 50% should be considered if the turbine is in poor condition, there is a high possibility of an underfrequency event, or if the unit is not system critical. If the unit is in good condition, an underfrequency event is unlikely and the unit is critical to the system, a setting near 90% of the allowable underfrequency time should be considered. It should be recognized that some underfrequency relay timers have an instantaneous reset once the frequency rises above the trip setting, while others accumulate the underfrequency operate time in a memory function (zero reset). The time-delay setting should be a smaller percentage of the allowable time if the relay is of the instantaneous reset type, whereas the zero reset relay may be set at a greater percentage of the allowable time.

The multiple underfrequency relay and timer schemes typically are not used on CTGs. CTG manufacturers generally provide the underfrequency protection and this usually consists of a single step underfrequency trip. The trip level should be obtained from the manufacturer.

4.5.8.4 Tripping mode

The underfrequency relays and timers are usually connected to trip only the GSU transformer high-side breaker(s) if such operation is permitted. However, in those cases where the consequences of a loss of machine are catastrophic, a utility may only alarm with the underfrequency protection and accept the possibility of doing some damage to the turbine. Overfrequency protection relays are typically connected to alarm only.

4.6 Backup protection

The protective relaying described in the preceding subclauses provides protection for all types of faults in the generator zone and for generator abnormal operating conditions. In addition to this protection, it is common practice to provide protective relaying that will detect and operate for system faults external to the generator zone that are not cleared due to some failure of system protective equipment. This protection, generally referred to as *system backup*, is designed to detect uncleared phase and ground faults on the system.

4.6.1 Phase fault backup

Two types of relays are commonly used for system phase fault backup: a distance type of relay or a voltage-restrained or voltage-controlled time-overcurrent relay. The choice of relay in any application is usually a function of the type of relaying used on the lines connected to the generator. In order to simplify coordination, the distance backup relay is used where distance relaying is used for line protection, while the overcurrent type of backup relay is used where overcurrent relaying is used for line protection.

4.6.1.1 Application of distance type of backup

One zone of distance relaying with a mho characteristic is commonly used for system phase fault backup. These relays are usually connected to receive currents from CTs in the neutral ends of the generator phase windings and potential from the terminals of the generator. If the generator is connected to the system using some means other than a delta-wye step-up transformer (e.g., direct connection, wye-wye transformer), then standard CT and VT connections made to a standard mho distance relay will provide accurate measurement of impedances for system faults (neglecting in-feed). However, if there is a delta grounded-wye step-up transformer between the generator and the system, special care should be taken in selecting the distance relay and in applying the proper currents and potentials so that these relays see correct impedances for system faults. With some relay designs, the phase angle of the voltages applied to the relay have to be shifted so that they are in phase with the system voltages in order for the relay to see system faults correctly. If required, this phase shift is accomplished by using auxiliary VTs connected in delta-wye as shown in Figure 4-49. (Note that this is a phase shifting transformer only. The turns ratio is chosen so that the line-to-line voltages on either side of the auxiliary VTs are 1:1). When a generator is connected directly to a system, the connections to the relay are shown in Figure 4-50. In both cases, for the connections shown, the relay will not only provide backup for system faults but it will also provide some backup protection for phase faults in the generator and generator zone before and after the generator is synchronized to the system.

In some cases, the distance relay is connected looking toward the system receiving both current and potential from the terminals of the generator. In this approach an offset mho characteristic is used to provide backup protection for system faults and for some generator and generator zone faults when the generator is connected to the system. However, this connection will not provide backup for the generator or generator zone when the generator is disconnected from the system.

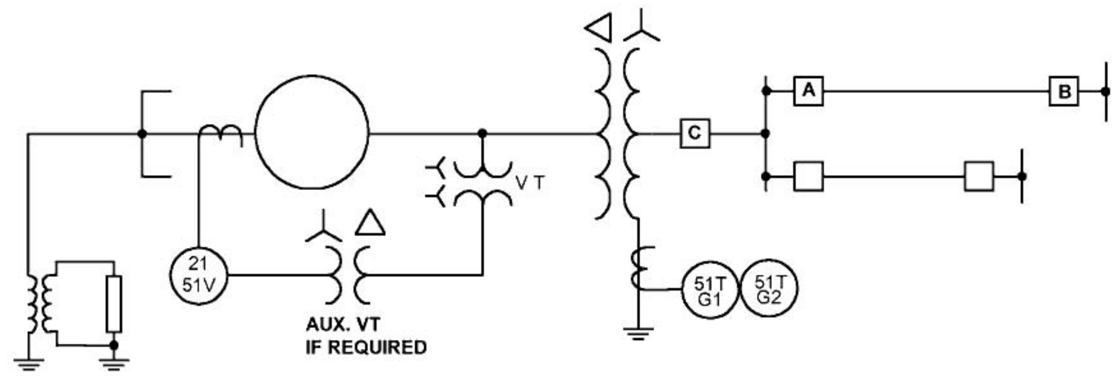


Figure 4-49—Application of system backup relays—unit generator-transformer arrangement

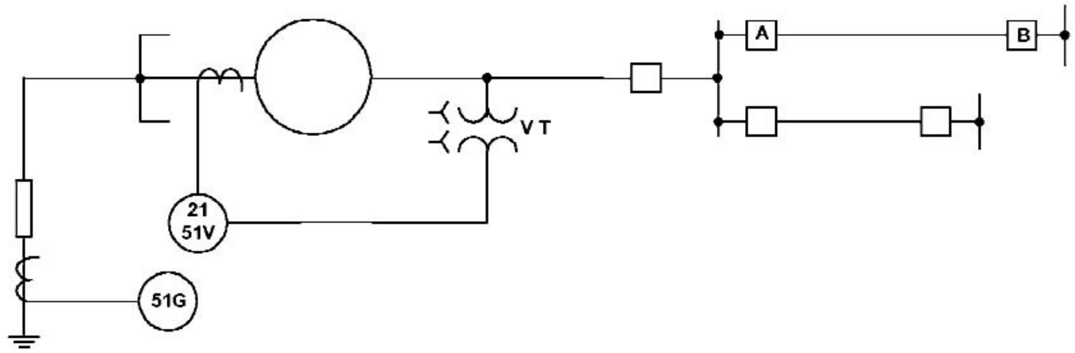


Figure 4-50—Application of system backup relays—generator connected directly to the system

The distance relay applied for this function is intended to isolate the generator from the power system for a fault that is not cleared by the transmission line breakers. In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and normal loading conditions. However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear (see Gantner and Wanner [B155]). It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers to optimize coordination while still protecting the turbine generator. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders can prevent misoperation for these conditions. Within its operating zone, the tripping time for this relay should coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus (see IEEE Power System Relaying Committee Report [B157]).

With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the Zone 1 element on the shortest line off of the bus. The normal Zone 2 time-delay criteria would be used to set the delay for this element.

Alternatively, Zone 1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting.

4.6.1.2 Overcurrent type of backup

In general, a simple time-overcurrent relay cannot be properly set to provide adequate backup protection. The pickup setting of this type of relay would normally have to be set from 1.5 to 2 times the maximum generator rated full-load current in order to prevent unnecessary tripping of the generator during some emergency overload condition. The settings should be reviewed to ensure that the relay will not operate during a system emergency, where the generator terminal voltage will be depressed and the stator currents will be higher.

With this pickup setting and with time delays exceeding 0.5 s, the simple time-overcurrent relay may never operate since the generator fault current may have decayed below relay pickup. After 0.5 s or more, generator fault current will be determined by machine synchronous reactance, and the current magnitude could be well below generator rated full-load current, which would be below the relay setting.

The type of overcurrent device generally used for system phase fault backup protection is either a voltage-restrained or voltage-controlled time-overcurrent relay. Both types of relays are designed to restrain operation under emergency overload conditions and still provide adequate sensitivity for the detection of faults.

In the voltage-restrained relay, the current pickup varies as a function of the voltage applied to relay. In one type of relay with zero voltage restraint, the current pickup is 25% of the pickup setting with 100% voltage restraint. On units that have a short, short-circuit time constant, the 51V voltage-restrained overcurrent relay should be used.

In the voltage-controlled relay, a sensitive low pickup time-overcurrent relay is torque controlled by a voltage relay. At normal and emergency operating voltage levels, the voltage relay is picked up and the relay is restrained from operating. Under fault conditions, the voltage relay will drop out, thereby permitting operation of the sensitive time-overcurrent relay. If applied properly, the overcurrent pickup level in both types of relays will be below the generator fault current level as determined by synchronous reactance.

The 51V voltage element setting should be calculated such that under extreme emergency conditions (the lowest expected system voltage), the 51V relay will not trip. However, during faults, within the protection zone of the relay, the relay will be enabled (51VC), or sensitized (51VR), to trip with the expected fault current level.

To provide system phase fault backup, three voltage-restrained or voltage-controlled time-overcurrent relays are connected to receive currents and voltages in the same manner as the distance relays illustrated in Figure 4-49 and Figure 4-50. In some small and medium size machine applications a single 51V relay is used, if a negative-sequence overcurrent is included. The two together provide phase backup protection for all types of external faults.

4.6.2 System ground fault backup

When a generator is connected in a unit generator-transformer arrangement, it is generally desirable to connect two inverse or very inverse overcurrent ground relays (51TG1 and 51TG2) to a high-accuracy CT in the GSU transformer neutral, as shown in Figure 4-49. When the generator is connected directly to the system, a single ground backup relay (51G) is connected to a CT in the generator neutral, as shown in Figure 4-50.

4.6.3 Settings

The phase and ground fault backup relays should be set to detect and operate for uncleared bus and transmission line faults outside of the generator zone. When the generating station and system configuration are simple as shown in Figure 4-49 and Figure 4-50, it is generally not difficult to obtain reasonable relay settings. Both the phase and ground backup relays are set to detect and operate for faults at the end of the longest line leaving the station. This is for a fault at breaker B on line A-B in Figure 4-49 or Figure 4-50.

On the other hand, if there are a number of generators and lines connected to the generating station as shown in Figure 4-51, it becomes difficult to obtain reasonable settings for the phase fault backup relays. Because of in-feed effects, sensitive relay settings may be required to detect faults at the end of the longest line.

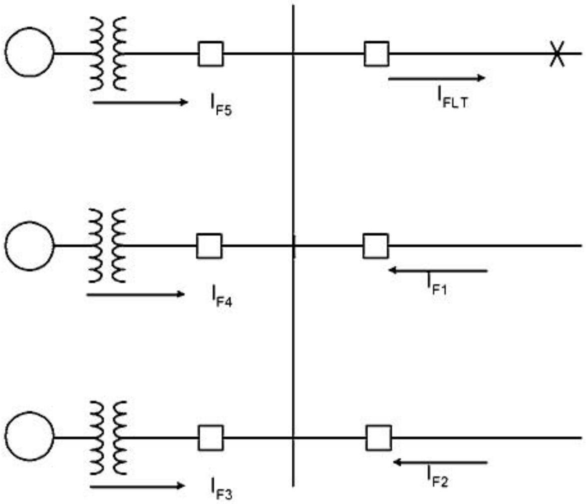


Figure 4-51—Complex system configuration

With these sensitive settings, the backup relays may operate under some loading conditions or for minor stable swings to unnecessarily trip a generator from the system. With this type of system configuration, it will generally be possible to set these backup relays to detect only close-in faults. Redundant line relaying and breaker failure relaying will have to be provided for line protection.

It should be noted that where VT type static exciters are used, the generator fault current may decay quite rapidly when there is low voltage at the generator terminals due to a fault. As a consequence, the overcurrent type of phase fault backup relay with long time delays may not operate for system faults. Therefore, the performance of these relays should be checked with the fault current decrement curve for a particular generator and VT static excitation system.

Both the phase and ground backup relays should be time coordinated with the protection on all system elements outside of the generator zone to assure proper selectivity; however, this may not always be possible.

4.6.4 Tripping mode

Phase faults: The 21 and/or 51V phase relays provide backup protection for phase faults. These relays are connected to energize a hand-reset lockout relay, which trips the main generator breakers(s), the generator field and/or exciter breakers, the low-side breakers on the unit auxiliary transformers (UATs), and the prime mover.

Ground faults: Relays 51TG1 and 51TG2 provide two steps of ground fault backup protection. Relay 51TG1 is coordinated with the highest-set ground relay on the transmission lines connected to the station bus (refer to 4.6.3). This relay is connected to trip the GSU transformer high-side breaker(s) only (Breaker C in Figure 4-49) and thus disconnect the generator and leave it isolated on its station service—if such operation is permitted—whenever a transmission line fault fails to clear.

If the ground fault is in the GSU transformer itself, operation of relay 51TG1 will not be effective in clearing the fault. This will require relay 51TG2, which is coordinated with 51TG1, to operate and shut down the generator in the same manner as described for the 21 and 51V relays.

Relay 51G provides a single step of ground fault backup protection for the generator in Figure 4-50. It will generally be connected to trip the same as the unit backup phase relays (21 and/or 51V).

4.7 Generator breaker failure protection

Functional diagrams of two typical generator zone breaker failure schemes are shown in Figure 4-52a and Figure 4-52b. Like all such schemes, when the protective relays detect an internal fault or an abnormal operating condition, they will attempt to trip the generator and at the same time initiate the breaker-failure timer.

If a breaker does not clear the fault or abnormal condition in a specified time, the timer will trip the necessary breakers to remove the generator from the system. As shown in Figure 4-52a, the breaker-failure timer is initiated by the combination of a protective relay and either a current detector (CD) or a breaker “a” switch, which indicates that the breaker has failed to open. Figure 4-52b shows a variation of this scheme that times out and then permits the CD to trip if current continues to flow. The reset time of the CD need not enter into the setting of the BF timer. The breaker “a” switch is used since there are faults and/or abnormal operating conditions such as stator or bus ground faults, overexcitation (V/Hz), excessive negative sequence, excessive underfrequency, reverse power flow, etc., that may not produce sufficient current to operate the CDs. If each pole of the breaker operates independently, breaker “a” switches from all three poles should be paralleled and connected into the logic circuit.

While there are a number of methods of initiating the breaker-failure scheme with protective relays, it is generally desirable to separate the generator zone protection into groups and have each group operate a separate lockout or auxiliary relay that would trip the generator and initiate the breaker-failure scheme. In this way, a single lockout or tripping relay failure will not eliminate all protection. It should be noted that all of the protective relays in the generator zone should be connected to the breaker-failure scheme.

Another factor to consider is the operating procedure when a machine is shut down for maintenance. When a ring bus, or a breaker-and-a-half or a double breaker-double bus arrangement is used on the high side, some utilities isolate the unit generator and close the high-voltage breakers to close the ring or tie the two buses together. Under these conditions, it will be necessary to isolate the lockout and trip relay contacts in order to prevent unnecessary breaker-failure backup operation during generator relay testing. Test switches are sometimes used for this function. It should be noted that if the generator is connected to the system through two circuit breakers, each breaker should be equipped with a breaker failure relay.

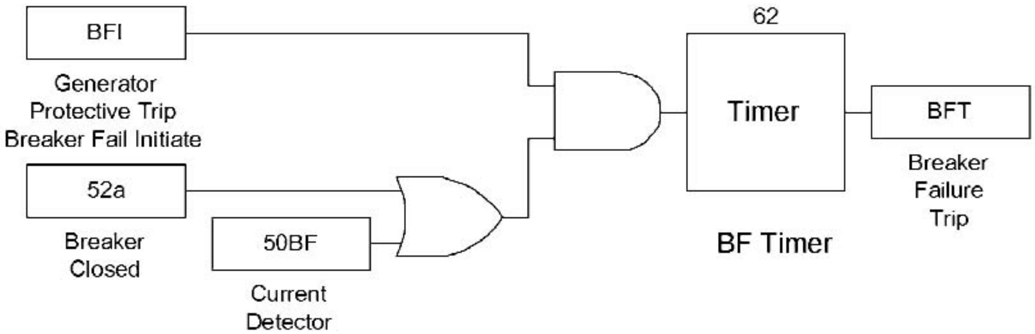


Figure 4-52a—Functional diagram of a generator zone breaker failure scheme

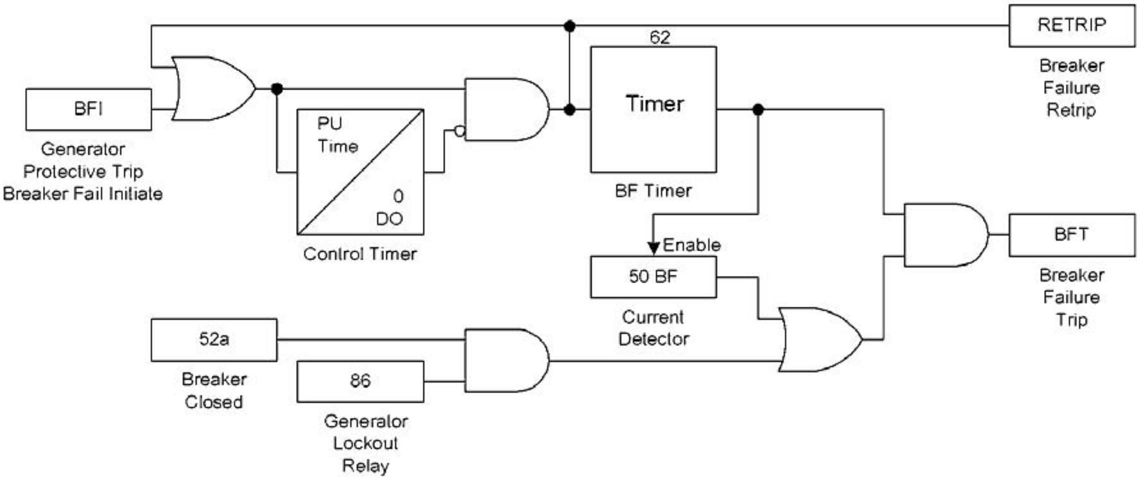


Figure 4-52b—Functional diagram of alternate generator breaker failure scheme

4.7.1 Open generator breaker flashover protection

Another form of breaker failure that may occur and damage the generator is an open breaker flashover; that is, an internal or external flashover across the contacts of one or more breaker poles to energize the generator. This is most likely to occur just prior to synchronizing or just after the generator is removed from service when the voltage across the generator breaker contacts approaches twice normal as the generator slips in frequency with respect to the system. Although circuit breakers are rated to withstand this voltage, the probability of a flashover occurring during this period is increased. Rarely are such flashovers simultaneous three-phase occurrences. Thus most protection schemes are designed to detect the flashover of one or two breaker poles.

If one or two poles of a breaker flashover, the resulting unbalance current will generally cause the generator negative-sequence relay or possibly ground overcurrent backup relays to operate, which will initiate a tripping of the flashed-over breaker. However, since the breaker is already open, breaker failure relaying is initiated. Breaker failure relaying as shown in Figure 4-52a is initiated if CDs are set with sufficient sensitivity to detect this situation.

An approach used to speed up the detection of a high-voltage unit breaker flashover is to modify the breaker-failure scheme as shown in Figure 4-53. An IOC relay (50G) is connected to the neutral of the GSU transformer. The relay’s output is supervised by the generator breaker “b” contact and provides an additional start to the breaker-failure scheme. When the generator breaker is open and one or two poles of the breaker flashover, the resulting transformer neutral current is detected by the 50G relay without the delay that would be associated with negative-sequence or neutral backup relays. Again, CDs associated with the generator breaker failure should be set with sufficient sensitivity to detect this flashover condition (see IEEE Committee Report [B152]). Generator breaker flashover may also be detected by breaker pole disagreement relaying. This relay monitors the three-phase currents flowing through the breaker and senses whether any phase is below a certain low threshold level (indicating an open breaker pole) at the same time that any other phase is above a substantially higher threshold level (indicating a closed or flashed-over pole). For breaker-and-a-half or ring-bus application, $3V_0$ voltage across the breaker is used to supervise the relay tripping to prevent false operation due to unbalance currents caused by dissimilarities in phase bus impedances.

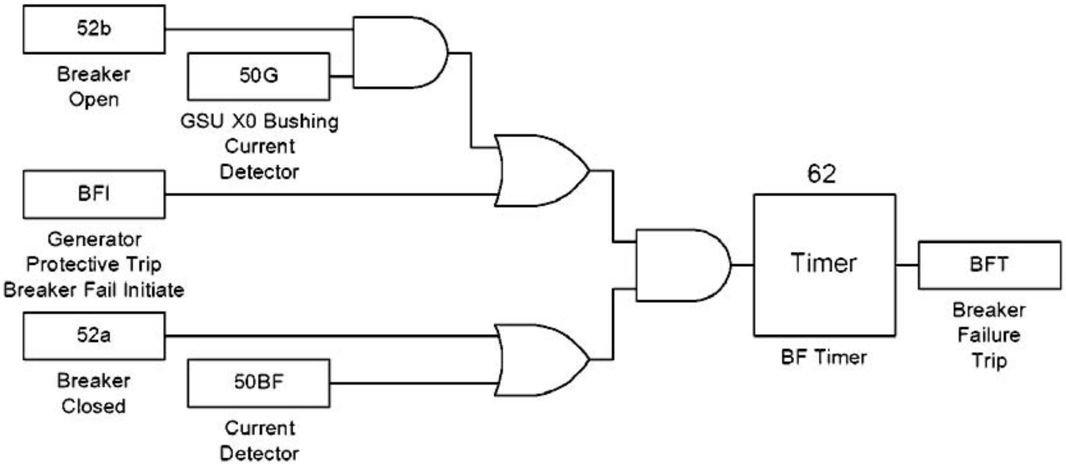


Figure 4-53—Modified breaker failure for open breaker flashover detection

4.7.2 Tripping modes

Breaker-failure schemes are connected to energize a hand-reset lockout relay that will trip the necessary backup breakers.

4.8 Excitation system protection

The excitation system has many similarities to the generator it supplies, and hence requires much of the same kinds of protection. Although the consequences from equipment failure may be less serious, more or less in proportion to its rating, adequate protection of the excitation system is important for reasons of continuity of service.

4.8.1 General

There are a number of excitation system types in use and/or currently being produced. Although numerous, very few dc (commutator) exciters are now produced, so these are not considered here.

Present-day exciters fall into two broad categories: those using ac generators (alternators) as a power source, and those using transformers. This difference has some effect on protection requirements, and this will be noted where it occurs. Both types use rectifiers, usually either silicon diode or thyristor, or both, that may be either air- or water-cooled.

Because the protection requirements are so closely related to the design of the excitation system and often require more specialized hardware than standard relays, the protection equipment should be, and normally is, included as part of the excitation system.

Physically, the protection may be provided by applying discrete component relays, microprocessors based protection, protection embedded in the excitation system control, or most likely in a combination. Traditionally, it has been preferred to have the critical protective functions separate from the excitation system control although many of the controls and limiters are an integral part of the system.

Table 4-1 lists protective function commonly associated with rotating and static exciters.

Table 4-1—Protective functions associated with exciters

Rotating (alternator type)	Potential source (static type)
Short circuit	Short circuit
Ground fault	Ground fault
Phase unbalance	Phase unbalance
V/Hz	V/Hz
Overcurrent	Transformer overcurrent
Loss of rectifier cooling	Loss of rectifier cooling
Armature winding temperature	Transformer winding temperature
Bearing vibration	
Bearing temperature	

Table 4-1 itemizes generally recommended protective functions and differentiates the protection of rotating and static type excitation systems. The equipment manufacturer may include more specific excitation protection in its particular systems.

4.8.2 Exciter phase unbalance

A phase-to-phase, internal turn-to-turn fault, or an open winding may each produce an unbalance in the normally balanced three-phase excitation power source. Detection may be by a detector that compares the three-phase voltages with their average, or by differential relays as used for generator stator phase faults. The latter are not useful for detecting shorted turns.

In some excitation systems, the alternator/transformer voltage varies with excitation requirements. In these cases, the phase unbalance detector should operate over a very wide voltage range, such as 10:1.

Since phase unbalance may be symptomatic of a serious problem, the unit should be tripped as quickly as possible. Tripping of turbine-generator line breaker(s) and excitation is recommended.

4.8.3 Exciter ground fault

A phase-to-ground fault may occur on an alternator/transformer winding or in the rectifier connected to it. As is the case with the generator field, one ground alone typically will cause no harm, but a second ground could cause heavy current flow and consequent damage.

Since the rectifier is normally connected to the generator field, and the latter should have a ground relay, most grounds in the rectifier will be detected by the same relay. Thus, no separate ground detector is required.

When an alternator is used as an excitation power source, it has a field that is subject to ground faults. While the consequences from a fault are less serious than with the generator field, it is, nevertheless, recommended that the alternator field be provided with a ground detector. This may be connected to provide only an alarm.

4.8.4 Overcurrent

As with exciter ground faults, overcurrent protection for the exciter alternator/transformer/rectifier cannot be separated from that required for the generator field. While cylindrical-rotor generator field current capability is defined by IEEE Std C50.13 in terms of field voltage versus time, the excitation system current capability depends on the design of the equipment and in general will be greater than that of the field.

Because of the shape of the IEEE C50.13 curve, some kind of inverse current versus time protection is indicated. Where the alternator/transformer/rectifier capability is less than that of the generator field, the protection characteristics should be modified to reflect this.

Another factor that should be incorporated into the design of the protection system is the need for field forcing following faults to aid in maintaining transient stability. This dictates that very high induced field currents are permitted to flow for short periods without causing the voltage regulator to reduce the field voltage because of the high current.

The overcurrent protection should be designed to correct the problem, if possible, and keep the unit online. If the problem is one that does not yield to preprogrammed control actions in a fixed, short time, then a unit trip signal should be produced.

4.8.5 Loss of rectifier cooling

The semiconductor rectifiers used in most excitation systems are dependent upon forced cooling, either air or water. Because of the short thermal time constant involved, it is imperative that load (that is, field) current be reduced or removed in a matter of several seconds if cooling medium flow is lost or greatly reduced.

The method and details of loss-of-flow detection will be dependent, in part, upon the design of the rectifier and its cooling system. In addition to the loss-of-flow signal, it is advisable to provide an over-temperature alarm.

4.8.6 Alternator armature winding over-temperature

The alternator, in excitation systems that use one, is somewhat like the main generator on a small scale. As such, it is subject to many of the same faults and requires similar protection. Overheating of the stator winding is one example of this. The stator winding could overheat due to partial failure of the stator cooling system, for example.

Stator winding temperature may be monitored by imbedded TCs or RTDs. Since such a problem is likely to arise relatively slowly, an alarm is considered adequate for protection.

4.8.7 Alternator air cooler loss of water flow

One possible cause of stator winding over-temperature is loss of air cooler water flow. While the alternator may be sufficiently protected by the stator winding over-temperature alarm, loss of water flow to the air coolers provides a backup and early warning. This is considered to be an optional protection.

4.8.8 Bearing and shaft vibration

Alternator bearings, in systems that have separate alternators, should be treated in the same manner as other bearings in the turbine generator. That is, they should be provided with vibration detectors (e.g., shaft proximity probes or housing-mounted accelerometers), transducers, and monitoring instrumentation. Specific alarm and trip recommendations should be made by the alternator manufacturer. In general, for lower levels of vibration, the recommendations will be to correct when convenient or at first opportunity, with the urgency increasing with vibration level.

4.9 Power transformer protection through mechanical fault detection

Protection through mechanical fault detection for the unit transformer and UAT is provided through gas detection devices and fault pressure relays. For further details, see IEEE Std C37.91.

4.9.1 Gas detection

Combustible gases, generated as the oil and insulation breaks down due to localized heating, are detected to indicate incipient faults. A relay may detect gas accumulations above a predetermined level by using a gas accumulator device connected between the main and conservator tanks or a gauge and float chamber connected by tubing to the high point of the transformer cover. This relay action would activate an alarm. A rapid accumulation due to a severe fault is detected by another part of this device and may be used to remove the transformer from service.

4.9.2 Fault pressure

Sensitive protection for a transformer may be provided using a sudden pressure relay based on mechanical principles. Detection methods use the pressure waves that are created during fault conditions inside the insulating oil of the transformer. An internal fault in the transformer will cause a sudden movement of oil within the transformer that in turn causes a pressure wave. This pressure wave will initiate operation of the fault pressure relay. On the other hand, small oil pressure rises due to changes in loading or ambient are gradual changes and are relieved by the device. Relay sensitivity and response to a fault is independent of transformer operating pressure.

High current faults in the high side of the unit transformer may cause CT saturation that may inhibit operation of the 87T or 87O differential relays. Similarly, high-side UAT faults may cause CT saturation that disables both the 87T and 50/51 relays. In these cases, the fault pressure relays provide the required protection. These relays also are needed to detect ground faults in the transformer medium voltage windings that the differential relay 87O cannot see due to the low-resistance grounding of the medium voltage auxiliary system.

4.9.2.1 Protection

Relays that respond either to sudden pressure changes in the gas above the oil or in the oil itself are used to detect a fault within the transformer tank, with more sensitivity than a differential relay. They have an inverse-time characteristic to respond faster to more severe faults, and yet will not trip under normal pressure variations experienced with loading and temperature changes.

4.9.2.2 Tripping modes

Both the unit transformer and the UAT fault pressure relays should be connected to lockout relays that are separate from the lockout relays connected to the differentials. In some system configurations, these lockout relays trip the main generator and field and/or exciter breakers, trip the prime mover, and transfer the unit auxiliaries. However, if the UAT has a breaker to isolate it from the generator bus, then that breaker may be tripped and the unit auxiliaries transferred without affecting the generator or field and exciter breakers or tripping the prime mover. See the cautionary advice in 4.5.1.4.

5. Other protective considerations

5.1 Current transformers

The performance of the sensitive, high-speed differential protection used in the generator zone depends to a large degree on the overall performance of the CTs used with these schemes. While there are a number of factors that may affect CTs, of particular concern are the effects of residual flux and stray external flux fields (proximity effects).

5.1.1 Residual flux

Residual flux may be left in cores of conventional CTs by normal interruption of an offset fault current and by the use of direct current (dc) in the testing of CTs. With regard to the latter point, it is common practice to use a dc source to check CT polarity and circuit continuity. When making these tests, the interruption of the dc source may leave high levels of residual flux in the core. This residual flux may adversely affect both the steady-state and the transient performance of the CTs used in a differential scheme, especially when the residual flux levels are different in each CT.

With unequal residual flux levels in differentially connected CTs, the difference in ratio errors between the CTs may be sufficient to cause the misoperation of sensitive differential relays under normal load conditions. Under fault conditions, residual flux levels may cause rapid unequal saturation of the differential CTs, which in turn may prevent operation or cause incorrect operation of a differential scheme for internal or external faults respectively.

The effects of residual flux may be minimized by demagnetizing the CTs after they have been tested during a maintenance shutdown. The use of CTs with small air gaps in the core (i.e., low-remanence type CTs) will greatly reduce the effects of residual flux. These CTs are generally designed to limit residual flux below 1.5 kG where the residual will have little or no effect on CT performances.

Demagnetization of high ratio generator CTs may be accomplished by connecting an ac source to the CT secondaries and raising the secondary voltage until the CT is driven into saturation as determined from the secondary excitation curve for the CT; the voltage should then be gradually decreased to zero. Some high ratio CTs may have high knee-point voltages that will fall in the 1000 V to 1500 V range. In these cases, a maximum applied voltage of 2000 V will generally be sufficient to saturate the CT.

CAUTION

The maximum applied voltage should never exceed the 2500 V dielectric test specified by IEEE Std C57.13 for CTs.

5.1.2 Proximity effects

The proximity of a current-carrying conductor to a CT may affect the overall performance of the CT. The stray flux field produced by the current-carrying conductor may cause both phase angle and ratio errors that in turn may cause incorrect operation of differential schemes under both steady-state (load) and fault conditions.

The adverse effects of stray fields (proximity effects) may be minimized by using CTs with shielded windings and, in some cases, with the use of twisted and shielded cable.

5.2 Voltage transformers

Loss of the VT signal may occur due to a number of causes. The most common reason is fuse failure. Other causes may be actual VT or wiring failure, an open in the draw-out assemblies, contact opening by corrosion, or fuse blowing due to screwdriver shorts during online maintenance. Such loss of VT signal may cause misoperation/failure to operate of protective relays or generator voltage regulator runaway leading to an overexcitation condition. This portion of the guide identifies schemes to detect the loss of voltage signal. Some method of detection is required so that the affected relay tripping may be blocked and the voltage regulator transferred to manual operation. This subclause also addresses additional concerns regarding the application of VTs. These are ferroresonance and grounding, as well as the use of current-limiting resistors.

5.2.1 Blown fuses

It is common practice, on large generators, to use two or more sets of VTs in the generator zone. These VTs, connected grounded wye-grounded wye, normally have secondary and possibly primary fuses and are used to provide potential to a number of protective relays and the voltage regulator. If one or more of the fuses blow in the VT circuits, the secondary voltages applied to the relays and voltage regulator will be reduced in magnitude and shifted in phase angle. This change in voltage may cause both the relays to misoperate and the regulator to overexcite the generator. The same effect may result from an open VT circuit.

5.2.1.1 Failure detection by comparison

To minimize the possibility of such misoperations, it is common practice to apply a voltage-balance relay that compares the three-phase secondary voltages of two sets of VTs as shown in Figure 5-1. If the fuses blow in one set of VTs, the resulting unbalance will cause the relay to operate. If a fuse blows in the voltage regulator VTs, the relay will alarm and remove the voltage regulator from service. If a fuse blows in the protective relay VTs, the relay will alarm and block possible incorrect tripping by protective relays whose performance may be affected by the change in potential. Typical relay functions such as 21, 40, and 51V are normally blocked.

Historically the relay has been set around 15% unbalance between voltages. A concern when considering the setting of this relay is that corrosion or poor contact of the VT stabs may result in a voltage drop in the circuit significant enough to cause a regulator runaway (overexcitation) but too small for detection by the relay. This is due to the sensitivity of the automatic voltage regulator circuitry.

5.2.1.2 Failure detection by symmetrical component analysis

A modern method used in VT failure detection makes use of the relationship between sequence voltages and currents during a loss of potential. When one VT signal is lost, the three-phase voltages become unbalanced. Due to this unbalance, a negative-sequence voltage is produced. Positive sequence voltage diminishes for a loss of a VT signal. To distinguish this condition from a fault, both negative and positive generator sequence currents are checked. This type of detection may be used when only one set of VTs are applied to the generator system.

5.2.2 VT application concerns

Two concerns will be addressed in this subclause regarding the proper application of VTs, as follows:

1) Ferroresonance and grounding
2) Use of current-limiting resistors

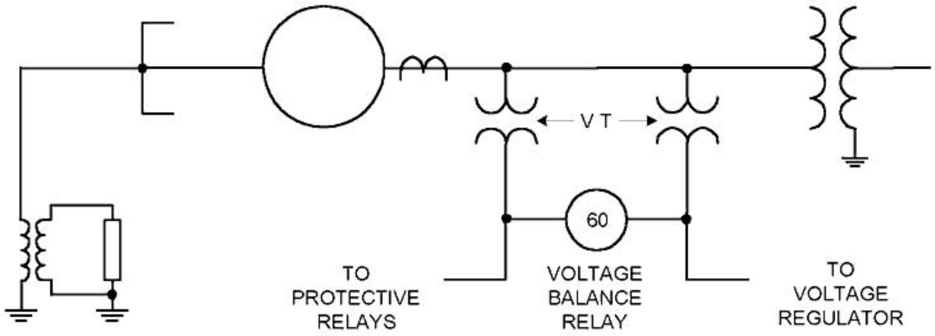


Figure 5-1—Application of voltage balance relay

5.2.2.1 VT ferroresonance and grounding

A ferroresonance phenomena may be created when wye-wye VTs with grounded primaries are connected to an ungrounded system.

This condition may occur in the generator zone if either the generator neutral becomes disconnected or the generator is electrically disconnected and the VTs are left connected to the delta winding of the unit transformer as illustrated in Figure 5-2. Should a higher than normal voltage be impressed across the VT windings during backfeeding due to a ground fault or switching surge on the ungrounded system, the likelihood of ferroresonance is enhanced. The higher voltage requires the VTs to operate in the saturated region that promotes the ferroresonance current jump phenomena. These high currents may cause thermal failure of the VTs in a short period of time.

By using line-to-line rated VTs connected line to ground, the potential for ferroresonance may be reduced. To completely suppress ferroresonance, it may be necessary to apply resistance loading across each phase of the secondary winding sufficient to damp out the oscillations.

This solution may be used during the above mentioned special operating conditions. During normal operation these resistive loads should be removed.

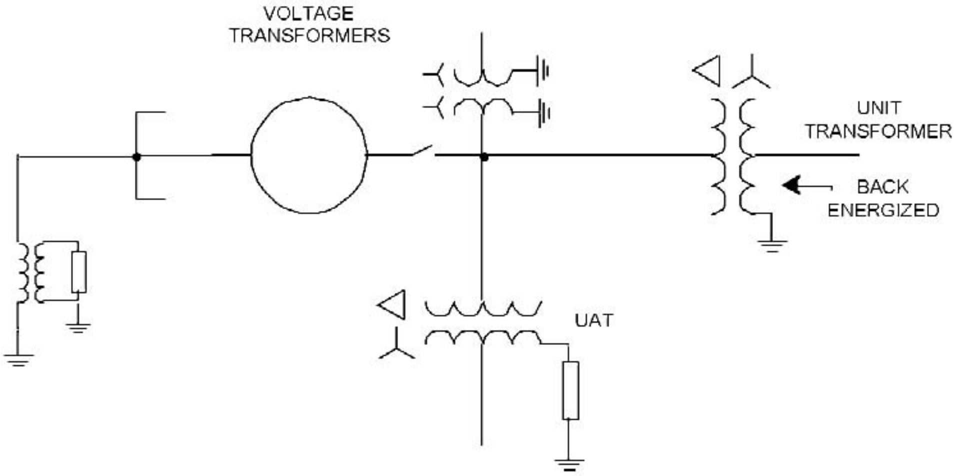


Figure 5-2—Generator zone configuration that may produce VT ferroresonance

Note that during this special operating condition that the normal ground fault protection is isolated from the energized system. Consideration should be given to installing a temporary ground-overvoltage relay connected to the VTs on the low side of the step-up transformer.

Permanent ground fault and overvoltage protection may also be applied. If the grounded wye-grounded wye VTs have an idle (unused) secondary winding, these idle windings may be connected into a broken delta configuration. By applying a damping resistance across the broken delta less than 45% (15% of $X_{m,}$ the magnetizing reactance, per phase) of the VT X_m, but not so low that the VTs exceed their thermal rating, the ungrounded bus system is stable against ferroresonance (see Peterson [B51]).

The minimum watt rating of this damping resistor may be calculated by squaring the $3V_0$ voltage across the broken delta connection when a bolted ground occurs on the primary bus, and dividing by the selected ohmic resistance of the resistor. A 60 Hz tuned ground overvoltage relay, also connected across the broken delta, may detect the arcing ground and clear the fault. If idle VT secondary windings are not available on the grounded-wye/grounded-wye main generator or main bus VTs, then a wye broken-delta auxiliary set of VTs loaded with the same relay and appropriate resistance across the open-delta may provide similar protection. The resistance loading on the idle windings or the auxiliary VTs is negligible until a ground develops while the unit step-up transformer is in the backfeed mode. For this reason, sizing of the resistor for the rated thermal capability of the VTs is recommended.

The criterion of $R_o \leq X_{co}$ for high-resistance grounded systems may be checked to see if the broken delta resistor's resistance R is low enough to limit transient overvoltages due to arcing ground faults. See IEEE Std 142. X_{co} is the primary side distributed per phase capacitive reactance to ground of the system and R_o is the effective primary side per phase resistance that equals R (VT voltage ratio)^2/3. If this criterion is met, transient overvoltages should not be a problem. With the primary system unenergized, X_{co} may be determined by applying a voltage V across the broken delta connection with the resistor, overvoltage relay, and all phase loads disconnected from the VTs on the isolated bus system and measuring the current I. Since I is predominately leakage current due to the system capacitance to ground, X_{co} may be approximately calculated by V (VT voltage ratio)^2/3I.

5.2.2.2 Use of current-limiting resistors

Current-limiting resistors are sometimes used in VT circuits from isolated phase buses to insure that current-limiting fuse ratings are not exceeded by fault current levels. Several issues arise that the user should be aware of the proper application of current-limiting resistors. A serious exposure occurs when only one resistor is used per phase with two or more VTs applied. Figure 5-3 illustrates this arrangement.

One concern is when the resistor fails open or partially fails inserting a high resistance in the circuit. The outcome of this is that with the open resistor both VTs are left with zero or reduced voltage signals. This condition would render the voltage balance relay inoperative and automatic voltage regulator runaway could occur.

Single switched voltmeter schemes would be impacted if connected to the afflicted phase. An operator may respond to the reduced voltage during a unit start-up by inappropriately increasing the field to the point of failure. In situations in which this has occurred, equipment damage has resulted.

A remedy to this problem is to provide a current-limiting resistor for each VT, thereby eliminating the common mode failure of both VT circuits. Figure 5-4 shows the suggested circuit arrangement for this remedy.

When requested, manufacturers provide this arrangement, the potential of the above mentioned conditions are minimized and allow the voltage balance relay to operate appropriately. Use of failure detection by symmetrical components provides VT failure detection when the common resistor arrangement is used for both generator VTs.

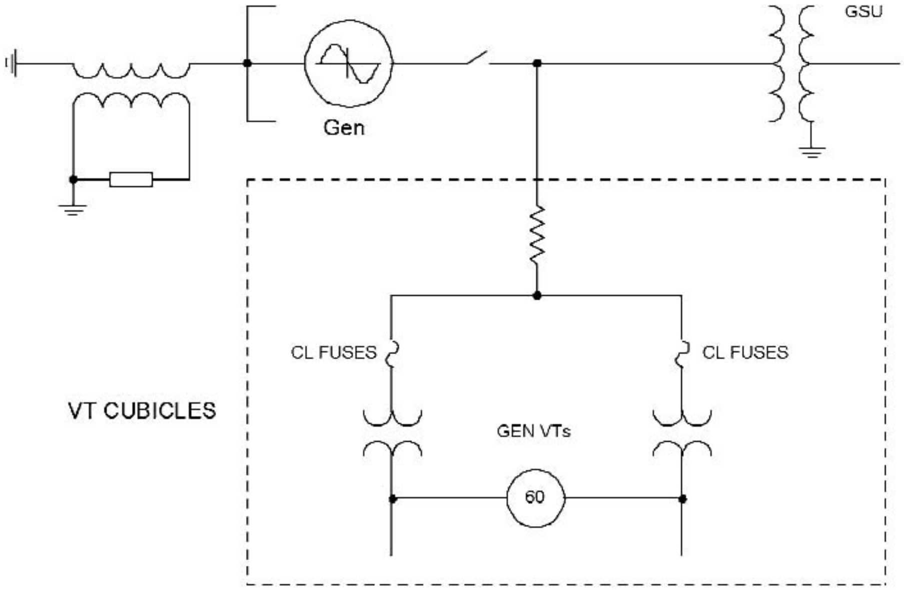


Figure 5-3—One current-limiting resistor per phase

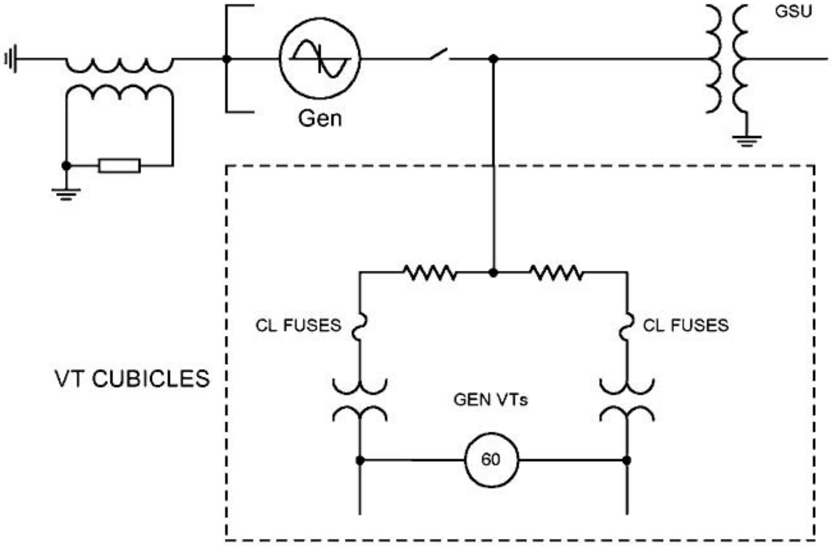


Figure 5-4—One current-limiting resistor per VT

5.3 Protection during start-up or shutdown

During start-up or shutdown of a generator, in particular, cross-compound units, the unit may be operated at reduced and/or decreasing frequency with field applied for a period of time. When operating frequency decreases below rated, the sensitivity of some of the generator zone protective relays may be adversely affected. The sensitivity of a few relays will only be slightly reduced while other relays will not provide adequate protection or become inoperative. Figure 5-5 shows the effects of frequency on the pickup of electromechanical relays that may be used in the generator zone. It should be noted that some relays lose sensitivity rather rapidly below 60 Hz. Induction disk current type relays may provide adequate protection down to 20 Hz while plunger type relays are not adversely affected by off-frequency operation.

Solid-state relays and digital protection systems have various frequency response characteristics. The specific effect of off-frequency operation should be checked with the manufacturer.

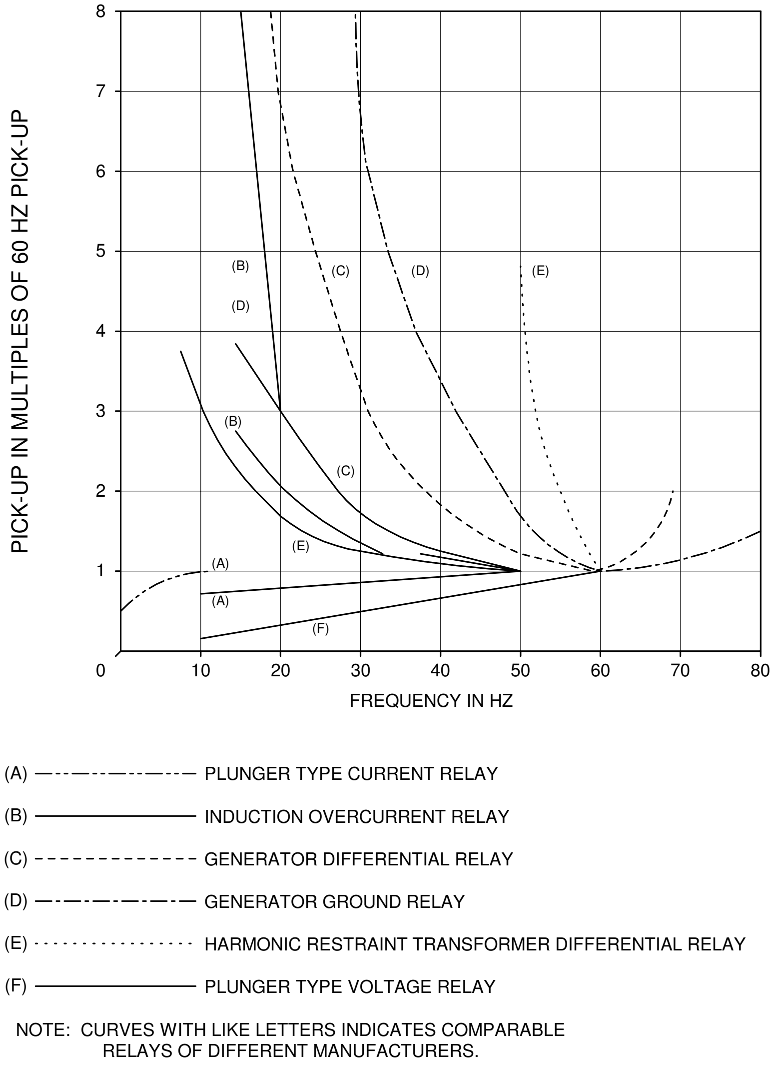


Figure 5-5—Example of relay pickup versus frequency

CT performance may be a problem at reduced frequency. The knee-point CT voltage capability decreases with frequency. While the reactive component of most relay burdens also decreases with frequency, the resistive component does not, nor does the lead resistance. Therefore, the reduction in CT capability is not fully compensated for by a reduction in total burden.

Supplementary protection during start-up or shutdown of a unit connected generator and its associated transformer may be provided through the use of protective relays whose pickup is not adversely affected by frequency, such as IOC or plunger-type voltage relays. Supplementary protection using plunger type relays is shown in Figure 5-6. In general, this protection would be placed in service only when the generator is disconnected from the system. A cut-off contact may be required to remove the relay from service to avoid exceeding the thermal rating of the relay.

Supplementary ground fault protection may be provided by using a plunger-type voltage relay connected in parallel with the normal ground overvoltage protection. Relays with a pickup range of below 10 V would be used for this purpose.

Supplementary phase fault protection may be provided by using plunger-type IOC relays in either one of two methods:

a) Placing IOC relays in series with the operate circuits of the overall transformer/generator differential relay.
b) Placing IOC relays in the CT phase leads that connect to the generator backup relays or metering.

The first approach a) is capable of providing sensitive supplementary protection. In this method, the IOC relay would be set above the difference current that will flow in the differential circuit during normal 60 Hz operation to avoid damage due to continuous operation in the picked-up position. In general, the difference current will be small and it will be possible in most instances to set the IOC relay at its minimum pickup setting.

One factor that should be considered when using this method is the effect of the IOC relay burden on the 60 Hz operation of the overall transformer/generator differential relays.

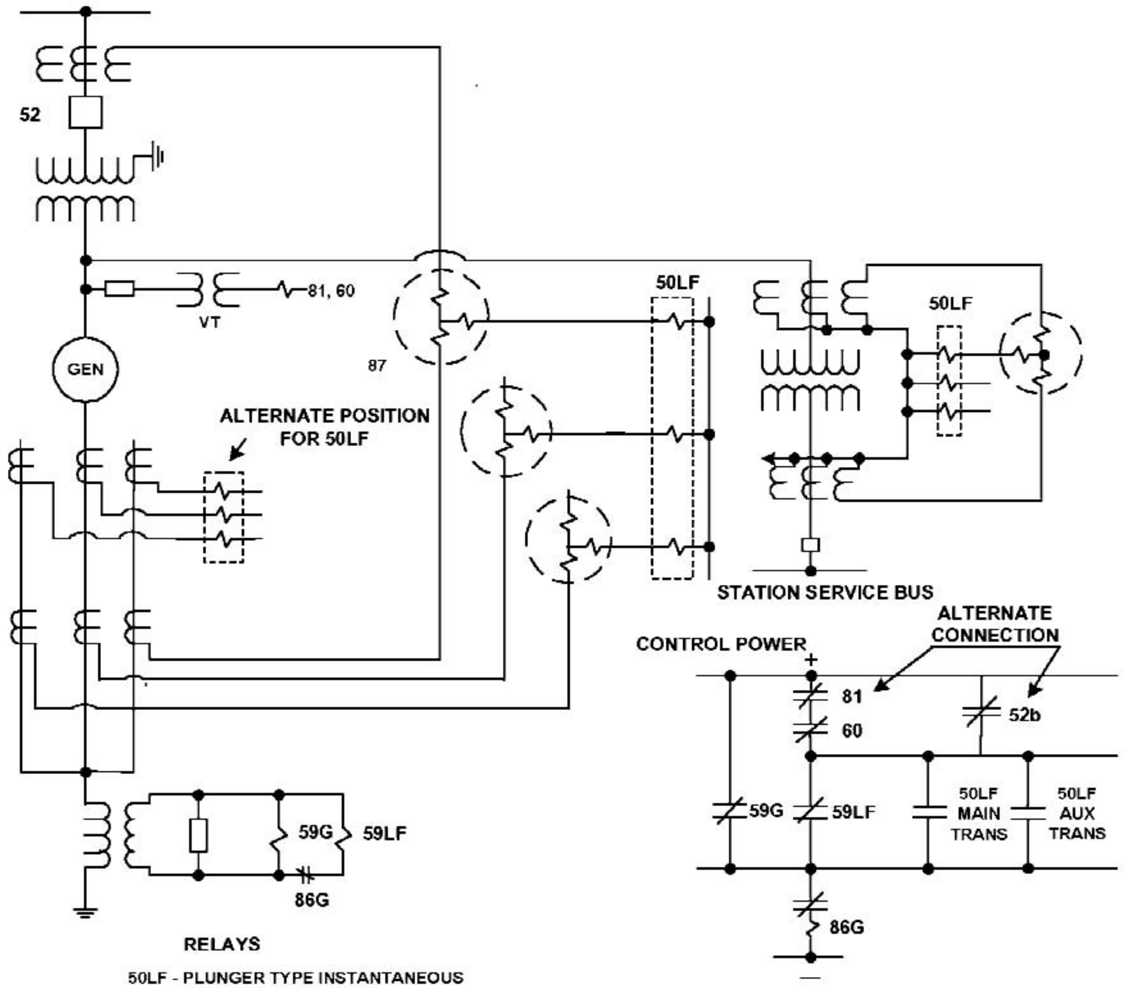
The IOC relay current coils will be in the differential circuit at all times and will present additional burden to the CTs. The effect of added burden on the low-voltage CTs will generally be negligible, but it may be necessary to check the ratio error of the high-voltage CTs.

When method b) is used (alternative position for 50LF in Figure 5-6), the plunger type of IOC relay would have to be set above maximum full-load current so that the relay would not be picked up continuously when the machine is online. This setting would not provide as sensitive protection during start-up or shutdown. If a pickup setting below full-load current is used, the IOC relay coil would have to be short-circuited before the machine is connected to the system since plunger relays cannot be operated picked up continuously. In general, short-circuiting current coils is not considered a desirable practice. Method (b) has an advantage in that it may also be used to provide protection for accidentally energizing a generator on turning gear. In this instance, it could be used in place of the fault-detector relay as discussed in 5.4.

When generators are bused at their terminals, supplemental ground protection could be provided by using a sensitive IOC relay in series with the time-overcurrent relay normally used for protection. These relays are connected to CTs located on the neutral end of the machine phase winding.

Supplemental phase fault protection could be provided by method b). In this case, it would be necessary to short-circuit both the phase and ground IOC relays current coil when the machine is connected to the system if both relays could be picked up continuously.

The supplementary protection for both types of generator arrangements may be deactivated when the units are connected to the system. This may be accomplished by opening the trip circuits with a breaker “b” switch, directional or voltage sensing relay, or with an underfrequency relay as shown in Figure 5-6. For discussion on *off-line overexcitation protection,* refer to 4.5.4.4.



RELAYS

50LF - PLUNGER TYPE INSTANTANEOUS OVERCURRENT RELAY
59LF - PLUNGER TYPE INSTANTANEOUS OVERVOLTAGE RELAY
81 - FREQUENCY RELAY 48-55 Hz
59G - TIME OVERVOLTAGE RELAY
87 - DIFFERENTIAL RELAYS

Figure 5-6—Protection during low-frequency operation

5.3.1 Protection of gas turbine generators during starting

Large gas turbines may be started by running the generator as a motor. The generator is run as a synchronous motor supplied by a static frequency converter (SFC) shown in Figure 5-7. The drive operates in a forced commutated mode at very low speeds until the synchronous machine emf is sufficient to commutate the inverter and in a load commuted mode thereafter. The SFC is connected to the generator bus so that generator terminal side and neutral side CTs see the same current. The gas turbine may be run for many minutes at different low speeds, while a purging cycle and firing cycle is completed, before it is finally accelerated to normal operating speed.

V/Hz is maintained constant as speed is increased until the voltage reaches drive rated voltage and thereafter voltage is held constant.

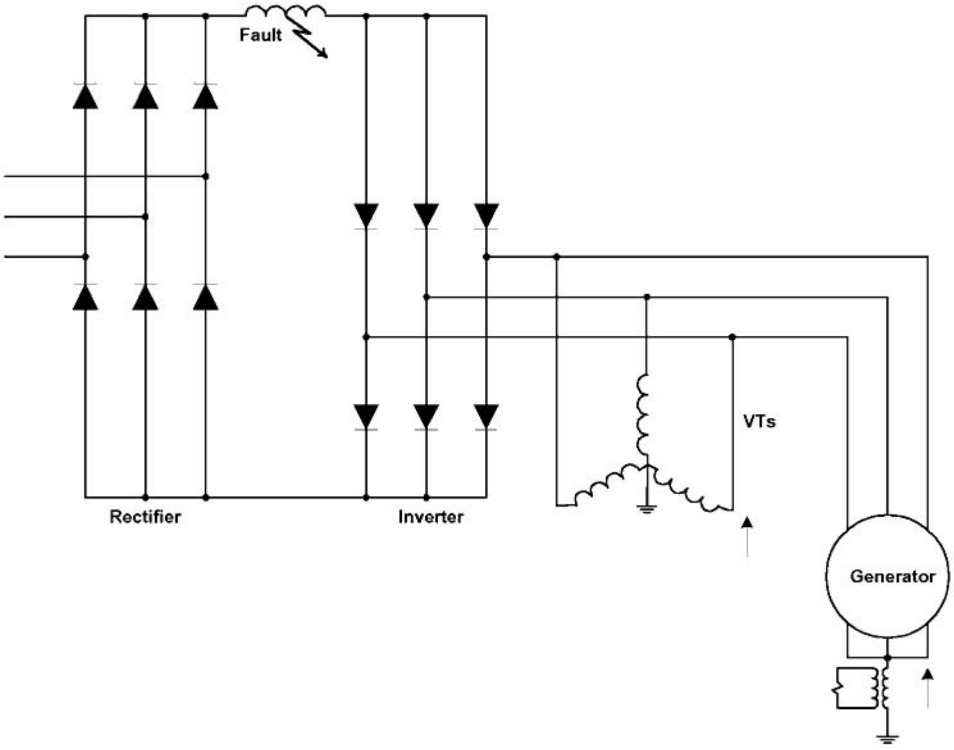


Figure 5-7—Static frequency converter

When the generator is operating at low frequencies, the normal protection has some limitations. Generally gas turbines are protected by multifunction protective relay systems. These relays normally track frequency within a specified frequency range, i.e., they sample and calculate the currents and voltages at a sampling rate that is an exact multiple of actual frequency. Over the specified frequency range the various protection functions will operate within their specified accuracy limits. Below the frequency tracking range, the sampling rate will no longer match the system frequency and the accuracy of the various elements will generally deviate outside of specification.

Curves of element performance versus frequency are often supplied by manufacturers down to some value of frequency. Multifunction relays provide protection down to a low frequency value but if a protective function characteristic is such that it may falsely operate at low frequencies, then it should be disabled during starting. In some installations single function relays, with good performance at low frequency, have been applied to provide additional protection during start-up.

The SFC also has protection functions, which will provide some protection for the generator stator. Typically they will include phase overcurrent, phase unbalance protection, and ground protection. The ground protection is likely to be insensitive if the generator is high-impedance grounded.

One fault that is not detected by either the conventional generator protection or the SFC is a fault on the dc bus of the rectifier/inverter. For this fault a dc current will flow though the fault and any ground in the ac system (see Figure 5-8). If the generator is grounded through a high-impedance grounded system (a distribution transformer and a secondary resistor) and there are wye-connected VTs, the fault current will divide between these two paths to ground, i.e., the generator neutral and the VTs. The dc current will cause the magnetic elements to saturate and current flow will be limited only by the dc resistances. The generator, the neutral grounding transformer, and the VTs all have limited thermal capability to withstand the dc currents flowing through them.

The approach used in many installations is to design the system so there are no ac grounds during starting. A switch is installed in the generator neutral to remove the neutral ground during starting, and the VTs are connected in delta. This ensures that there will be no dc current flow and resulting saturation of magnetic elements for a fault on the dc link is avoided. Since the VTs are ungrounded, third harmonic terminal voltage is unavailable and 100% stator ground fault protection is provided by the neutral third harmonic undervoltage method.

An alternative approach, used in some installations, is to keep the generator neutral grounded during starting and to detect a fault on the dc link by measuring the dc current in the generator neutral. For these faults, the VTs are usually the most limiting components, requiring very quick removal of the fault—as fast as 50 ms including the time taken to turn the adjustable speed drive off. On generators grounded through a resistance-loaded distribution transformer, protection schemes have been applied using a resistor/dc transducer between the grounding transformer neutral and ground. The output of the transducer is connected to a sensitive dc relay. Calculation and tests have confirmed the performance of this protection.

The setting is determined by equipment withstand and relay sensitivity. At low speeds there may not be enough driving voltage to trip the relay. In some installations the generator is high-resistance grounded through a resistor connected directly in the generator neutral circuit. For this type of installation, protection against faults in the dc link has been provided in a similar fashion as above by using a dc CT and a dedicated dc relay.

5.4 Inadvertent energizing

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 (see 4.7.1), control circuit malfunctions, or a combination of these causes has resulted in generators being accidentally energized while off-line.

This subclause discusses the problem of generator inadvertent energization, the limitations of conventional generator protection to detect this condition, and the use of dedicated inadvertent energizing protection schemes.

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. 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 backfed 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 energization; however, auxiliary transformers have failed.

5.4.1 Normally available relays

The normal relay complement for generator protection has serious limitations when trying to detect inadvertent energizing. Specifically, the following relays cannot be relied on to protect the generator for all inadvertent energizing conditions:

a) Loss-of-excitation relays
b) Reverse power relays
c) System backup relays
d) Negative-sequence relays

5.4.2 Dedicated protection schemes

Unlike conventional schemes, which provide protection when the generator is online, these schemes are designed to protect the generator when it is off-line. Great care is required to insure that dc tripping power and input quantities are not removed when the generator is off-line. Consideration should be given to locating this protection in the switchyard where it is less likely to be disabled during generator maintenance.

Relays that are voltage dependent are disabled if the standard procedure is to remove VT fuses when the machine is off-line. For some reverse power relays, with the potential applied, a voltage drop of 50% or more will usually render them inoperative. Relays with intentional time delay for coordination purposes are too slow to provide any substantial protection for inadvertent energization.

When assessing whether a relay will provide adequate protection, it is necessary to determine its status when the generator is off-line. There have been numerous cases reported where all of the generator protection was inoperative when the machine was accidentally energized. Common dedicated schemes used to detect inadvertent energizing include:

a) Directional overcurrent relays
b) Frequency supervised overcurrent
c) Distance relay scheme
d) Voltage supervised overcurrent
e) Auxiliary contacts scheme with overcurrent relays

5.4.2.1 Directional overcurrent

This scheme has three directional inverse time-overcurrent relays that use current and voltage sensing from the generator terminals. It is necessary to choose a relay with a maximum sensitivity angle combined with the CT connection to assure that the underexcited loading capability of the machine is not appreciably impaired. The setting used may involve a compromise between desired sensitivity and a setting at which the relay will not be thermally damaged by machine full-load current. This scheme is dependant on potential being present for operation. Thus, if operating procedures dictate removing VT fuses when the generator is off-line, this scheme is not recommended (see IEEE Committee Report [B152]).

5.4.2.2 Frequency supervised overcurrent

This scheme uses a combination of frequency and overcurrent relays that are only enabled when the machine is off-line. The current relays are IOC with a pickup setting of about half of the expected inadvertent energizing current. The underfrequency relays are set to close their contacts when the frequency falls below the setting, which is in the range of 48 Hz o 55 Hz, thus enabling the overcurrent relay. This scheme requires pickup and dropout time delays and voltage balance supervision to prevent misoperation. For this scheme to work properly, the underfrequency relay contact needs to be closed when there is no voltage. Underfrequency relays that do not operate below 50% voltage should not be used for this application.

5.4.2.3 Distance relay

There are a number of schemes developed using distance relays polarized to respond to current flow into the generator from the high-voltage switchyard. The distance relay is set to detect the sum of the reactance of the unit step-up transformer and the machine negative-sequence reactance with appropriate margin. In some cases, the distance relay is supervised by an IOC relay to prevent false operation on loss of potential. Since the impedance relay may operate for stable power swings, a thorough stability analysis is required to ensure the relay will not operate for such swings. Additional protection is required for single-phase energization, since the distance relay has limited capability to detect this condition (see IEEE Committee Report [B152]). Also, in order to prevent undesirable operations on recoverable swings, it may be desirable to delay operation of this relay by 0.1 s (see IEEE Committee Report [B123]).

5.4.2.4 Voltage supervised overcurrent

The scheme shown in Figure 5-8 uses under and overvoltage relays with pickup and dropout time delays to supervise IOC tripping relays. The undervoltage detectors automatically arm the overcurrent relays when its generation is taken off-line. Overvoltage relays disable the scheme when the machine is put back in service. This scheme does use potential from the generator VTs, but will work properly even if it is the practice to remove VT fuses when the generator is off-line. Voltage balance relay supervision or other VT fuse loss detection logic is required to prevent possible misoperation that may result from loss of potential due to VT fuse blowing. This scheme is well suited for location in the switchyard where it is less likely to be accidentally removed from service during generation maintenance.

5.4.2.5 Auxiliary contact-enabled overcurrent

The scheme uses the generator field breaker auxiliary contacts to enable non-directional IOC relays when the field breaker is either open or racked out. In some cases a speed switch is used. Overcurrent relays are set for 50% of the minimum accidental energizing current.

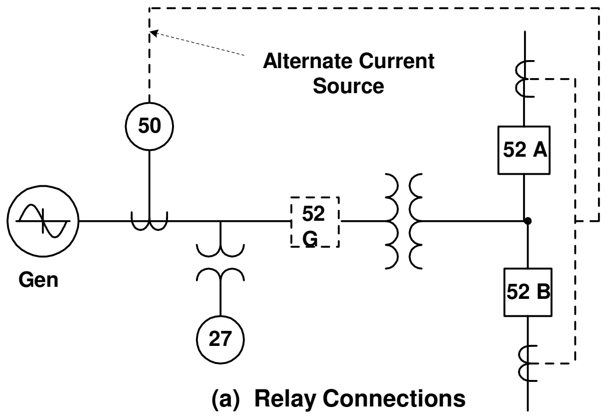
Coordination time delays are used to prevent misoperation. Although this scheme will not provide protection after the field is applied to the unit, it is preferred over the scheme that uses the auxiliary contacts of a motor operated disconnect and high-voltage generator breakers to supervise these same non-directional instantaneous relays. This latter scheme will provide accidental energizing protection for the unit regardless of the frequency or voltage applied to the unit. The drawback to this scheme is the complexity of the contact logic and the unreliability of the auxiliary contacts, particularly those on the motor operated disconnect. This kind of off-line supervision should be avoided.

WARNING

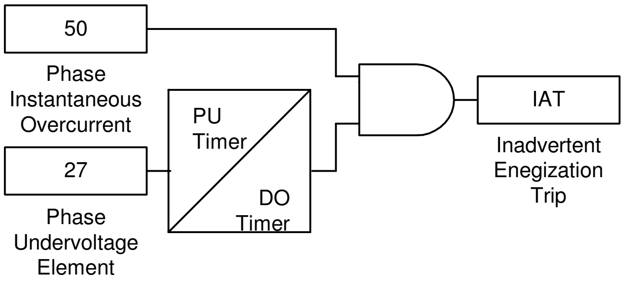
If the motor is disengaged from the disconnect switch such that the auxiliary contacts do not follow the switch position, inadvertent energizing protection may not be enabled when required to operate and personnel may be endangered.

5.4.2.6 Summary recommendations

Inadvertent energization protection was expanded in this guide to alert protection engineers to the real and devastating consequences of inadvertently energizing a generator. Conventional generator protection schemes are typically insensitive or so slow to operate and do not prevent the generator from being damaged. Therefore, it is recommended that some form of dedicated inadvertent energizing scheme be used as part of an overall generator protection package. This scheme should be installed in such a manner that it will not be disabled during plant shutdown or maintenance.



(a) Relay Connections



(b) Relay Logic Diagram

Figure 5-8—Voltage supervised overcurrent scheme

5.4.3 Tripping mode

These relays are connected to trip the generator breaker, field breaker, prime mover, and transfer auxiliaries.

5.5 Subsynchronous resonance (SSR)

When a generator is connected to a transmission system that has series capacitor compensation, it is possible to develop subsynchronous frequency oscillations and shaft torques that may be damaging to the generators. Therefore, when a generator will be operating on such a series compensated system, the user should work closely with the generator manufacturer in order to ascertain the severity of the problem and to define the requirements for equipment to protect the generator on a particular system. The successful mitigation of the oscillations may be accomplished by equipment selection, control, and protection techniques.

5.5.1 Equipment selection

Determination of the proper amount of series compensation to avoid SSR requires extensive studies.

5.5.2 Control

Several control techniques may dampen oscillations before a trip is necessitated. Some examples are the application of supplementary control in the excitation system to provide damping torque, subsynchronous blocking filters to limit subsynchronous currents, series capacitor bypass switches that close upon detection of SSR, and torsional dynamic stabilizers.

5.5.3 Protection

Protective devices may be applied to remove a generator from the system as the primary protection against SSR or as a backup to other SSR mitigation. A torsional relay may be set to trip for both low-level oscillatory torques that are growing in magnitude and for very high level torques occurring between different sections of the shaft. Relay inputs could include instantaneous shaft speed deviation or instantaneous generator power. A torsional protection relay may also be set to trip when oscillations persist.

5.5.4 Monitoring

Monitoring systems can be applied to turbine generators to record SSR events and provide information on shaft loss-of-life. One type of monitoring scheme calculates shaft torques from measurements of generator voltages and currents. Another alternative is to monitor actual shaft torques. Monitoring equipment enables post-event analysis, which may be helpful in evaluating the performances of SSR mitigation and protection systems.

5.6 Transmission line reclosing near generating stations

Switching operations involving the opening and closing of circuit breakers at or near a generating station may produce transient power and current oscillations that may stress or damage turbine generators. Of particular concern are the switching operations that produce torsional oscillations and shaft torques that may cause major shaft fatigue damage in one or relatively few incidents of severe switching disturbances. The switching disturbances of primary concern are as follows:

a) Steady-state switching of lines
b) High-speed reclosing of circuit breakers following transmission line faults

5.6.1 Steady-state switching of lines

The switching of lines near a generating station for maintenance purposes may produce a step change in power that may result in transient mechanical forces on both the rotating and stationary components of a turbine generator. This sudden change in power is a function of the switching angle across an open circuit breaker and the system impedance. Studies have shown that if during steady-state switching operations the instantaneous change in power, ΔP, does not exceed 0.5 pu, the duty (loss of life) on the turbine generator will be negligible. If this change in power, ΔP, exceeds 0.5 pu, it is recommended that the turbine-generator manufacturer be consulted in order to determine if there is potential for significant damage.

5.6.2 High-speed reclosing following system faults

High-speed reclosing of transmission lines at or near a generating station following a fault has the potential for causing major shaft fatigue damage to a turbine generator. Of particular concern is the possibility of an unsuccessful reclosure into a persistent fault that may reinforce the torsional oscillations and shaft torques caused by the original disturbance and thereby cause a significant loss in fatigue life of turbine-generator shafts. Studies of this problem would indicate that high-speed reclosing into nearby severe faults may result in a significant loss of shaft fatigue life.

In order to minimize the potential detrimental effects of high-speed reclosing of transmission lines near generating stations, the following alternative reclosing practices are being proposed as a means for minimizing fatigue duty:

a) *Delayed reclosing for all faults:* A delay of 10 s or longer is suggested.

b) *Sequential reclosing:* Reclose initially from the remote end of a line and block reclosing at the generating station if the fault persists. This approach is only applicable if the remote end of the line is not electrically near turbine-generator units. Reclosing remote on long lines may cause transient overvoltage if the other end of the line is a weak source.

c) *Selective high-speed reclosing*: The type of reclosing used (high-speed or delayed) is a function of fault severity or the type of fault.

d) *Single-phase tripping and reclosing:* Trip only the faulted phase and delay its reclose until after secondary fault arc extinction. This provides an advantage that the remaining connected phases tend to hold the machine in synchronism during the first clearing attempt, minimizing power swings, helping to maintain stability.

5.7 Synchronizing[7]

Improper synchronizing of a generator to a system may result in damage to the GSU transformer and any type of generating unit. The damage incurred may be slipped couplings, increased shaft vibration, a change in bearing alignment, loosened stator windings, loosened stator laminations, and fatigue damage to shafts and other mechanical parts.

In order to avoid damaging a generator during synchronizing, the generator manufacturer will generally provide synchronizing limits in terms of breaker closing angle and voltage matching. Typical limits are:

1) *Breaker closing angle:* Within ±10 electrical degrees. The closing of the circuit breaker should ideally take place when the generator and the grid are at zero degrees phase angle with respect to each other. To accomplish this, the breaker should be indexed to close in advance of phase angle coincidence to accommodate for the breaker closing time.

   This is mathematically expressed as shown in Equation (5.1):

$$\theta = 360\ F_S T_S \tag{5.1}$$

   where

   θ is the advance angle in degrees
   F_S is the slip frequency in Hertz
   T_S is the breaker closing time in seconds

2) *Voltage matching:* 0% to +5%. The voltage difference should be minimized and not exceed 5%. This aids in maintaining system stability by insuring some var flow into the system. Additionally, if the generator voltage is excessively lower than the grid when the breaker is closed, sensitively set reverse power relays may trip.

3) *Frequency difference:* Less than 0.067 Hz. The frequency difference should be minimized to the practical control/response limitations of the given prime mover. A large frequency difference causes rapid load pickup or excessive motoring of the machine. This manifests itself both as power swings on the system and mechanical torques on the machine. Additionally, if the machine is motored, sensitively set reverse power relays may trip.

Slip frequency limits applied for certain machine types are based on the ruggedness of the turbine generator under consideration and the controllability of the turbine generator and MVA.

There are several synchronizing approaches that may be used to minimize the possibility of damaging a generator, as follows:

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[7] See IEEE Std C50.12, 4.2.2, and IEEE Std C50.13, 4.2.4.2.

a) Automatic synchronizing
b) Semi-automatic synchronizing
c) Manual synchronizing

5.7.1 Automatic synchronizing system

Complete automatic synchronizing includes an integrated combination of elements that monitor voltage magnitude, phase angle, and rate of change of the phase angle across a controlled circuit breaker. It takes into account the closing time of the controlled breaker to predict when to initiate closing. This system includes an automatic synchronizer and elements (relays or modules) to monitor and control the frequency and voltage of the generator.

The synchronizing relay measures the speed of the generator relative to the system, the phase angle between the generator and the system, and then gives a closing impulse to the breaker at the correct angle in advance of synchronism to ensure that the breaker poles will close when the machine and system are in phase. For a given breaker closing time, the closing impulse will be given at the correct angle in advance of synchronism provided that the frequency difference is within a set limit. In general, there should be a small difference in frequency between the generator and the system for the synchronizing relays to operate.

The speed-matching relay is used to automatically match a generator frequency to a system frequency. To do this, the relay produces impulses that may be used to raise or lower generator speed. In general, generator speed is adjusted to be slightly higher than system frequency for synchronizing purposes to prevent motoring or tripping on reverse power. Sync-check relays are often applied with automatic synchronizers to supervise the automatic control function.

In some instances, the speed-matching and voltage-matching functions are provided with the automatic control systems supplied with the generator.

5.7.2 Manual and semi-automatic synchronizing systems

The manual synchronizing system relies on the operator’s judgment for breaker closure while controlling generator voltage and frequency. The information required for the operator to make a closing decision is provided by a group of instruments. The operator’s action may be supervised by additional devices, but are “transparent” to the operator, i.e., the devices act as permissive only and do not match speed and voltage or initiate closure.

The semi-automatic synchronizing system has aspects of both the manual and automatic systems in that the operator has supervision of the automatic device and may directly control the generator speed and voltage.

The relay used to perform the supervisory function is a sync-check relay. Depending on the sophistication of the applied relay, it may be of the phase angle/time and voltage variety or phase angle/slip relationship and voltage variety. The angular setting of the sync-check relay should be set to the maximum angle expected at the maximum slip frequency allowed for the particular application per Equation (5.1). Utilization of an intentional time delay on a sync-check relay may result in undesirable closure beyond phase coincidence. Additional increments in angle should be added to account for relay propagation time, accuracy, and contact debounce.

Both the closing angle and frequency difference cut-off are adjustable. In general, with this type of relay, the angular difference for synchronizing may be limited to 10° or less.

High-speed sync-check relays should be used for this supervisory role for either automatic or manual synchronizing applications due to the quick, repeatable response on rotation phase angle applications.

6. Multifunction generator protection systems[8]

6.1 Introduction

Generator protective relaying technology has evolved from discrete electromechanical relays and static relays to digital multifunction protection systems. Most protection schemes in service today are discrete electromechanical or static relay types that have a long history of providing reliable protection and continue to be applied in many applications. However, with the availability, additional performance, economic advantages, and reliability of digital multifunction protection systems, this technology is being incorporated into most new protection schemes. In most cases, new generators are being protected with either dual multifunction generator protection systems (MGPS) or a single multifunction generator protection, possibly backed up by some single function relays. Some modern excitation systems contain protection functions that may be considered as backup.

Because of the advantages of digital technology, multifunction protection systems are being retrofitted on older machines either to replace older discrete component electromechanical protection schemes, to augment existing protection or to add protection functions that are not on the older machines.

Digital technology offers several additional features that could not be obtained in one package with earlier technology. These features include: metering of voltages, currents, power, and other measurements; oscillography; sequence of events capture with time tagging; remote setting and monitoring through communications; user configurability of tripping schemes and other control logic; reduced panel space and wiring; low burden on the VTs and CTs; continuous self-checking and ease of calibration.

Figure 6-1 shows the block diagram of a typical MGPS. The general multifunction relay application is made up of two or more functions implemented on a single hardware platform. The MGPS has analog inputs (voltage and current signals), digital inputs, and digital outputs for sending trip and alarm signals. The MGPS may also have bi-directional communication ports, which may be RS-232, RS-485, fiber optic, or some other hardware interface for communicating with the external world. Internal hardware consists of an analog data acquisition system that includes signal scaling, isolation, filtering (anti-aliasing) analog multiplexing, and analog-to-digital conversion. The digital subsystem consists of a microprocessor, read-only memory (ROM) for program storage, random-access memory (RAM) for temporary storage of information, and electrically erasable programmable memory (EEPROM) for storage of set points.

The functional operation and performance of the MGPS are determined by both hardware and software programs. Digital signal-processing algorithms are used to filter the voltage and current input signals and calculate the parameters required for the relaying functions. The relay logic program compares the set points to the calculated parameters and implements the required time-delay characteristics. The software program also implements other features such as communications, oscillography, event record, and local user interface.

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[8] See IEEE/PSRC Working Group Report [B177].

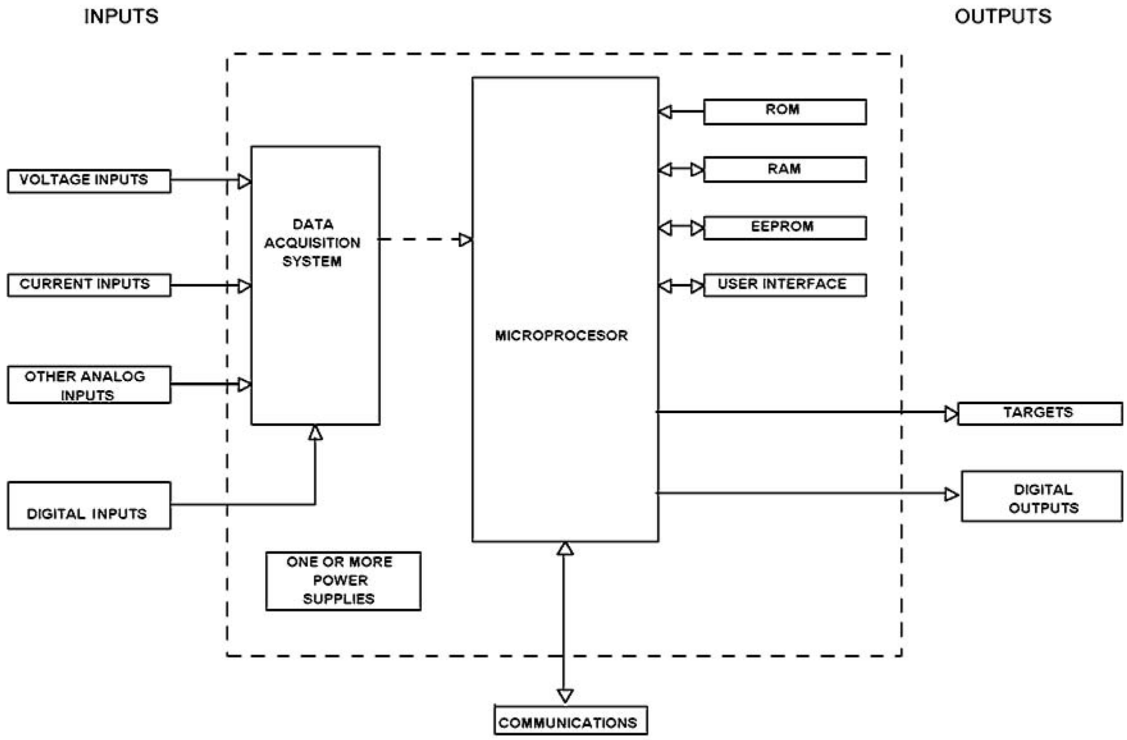


Figure 6-1—Block diagram of a typical MGPS

6.2 Application on a typical generating unit

6.2.1 Protective functions

Protective functions traditionally provided by individual component relays and now integrated into MGPS packages include two or more of the following:

a) Generator phase differential (87G)
b) Generator ground differential (87GN)
c) Transformer differential (87T)
d) Stator ground (59G)
e) 100% stator ground
f) Third harmonic neutral undervoltage (27TH)
g) Third harmonic voltage ratio or differential (59THD)
h) Subharmonic voltage injection (64S)
i) Current unbalance/negative sequence (46)
j) Loss of excitation (40)
k) Overexcitation (24)
l) Undervoltage (27)
m) Overvoltage (59)
n) Underfrequency (81U)
o) Overfrequency (81O)

p) Reverse power or directional power (32)
q) Thermal protection (49)
r) Overcurrent (51)
s) System backup (51VC/51VR) or (21)
t) Loss of voltage (60)
u) Out-of-step (78)
v) Field ground (64F)

Additional functions that may be provided include: sequential trip logic, accidental energization, and open breaker detection. By using programmed logic and appropriate protection elements within the MGPS, these functions may be implemented without the additional devices and wiring necessary with more traditional approaches. Because of the different functions keeping their characteristics over a wide frequency range, it may no longer be necessary to implement a separate start-up or shutdown protection.

6.2.2 Protective function arrangement and layout

Traditional applications of generator protective relays involved separate relays performing different functions with some overlap and backup where appropriate. In many cases, the generator differential relay was connected to a dedicated set of CTs due to reliability, burden, and CT characteristic matching issues. The low burden of an MGPS allows connection of differential and other protection to the same set of CTs without deterioration of performance caused by CT burden. The use of a single set of CTs is a concern to many application engineers because CT inputs are not duplicated in this scheme, resulting in lower reliability. However, if two MGPSs are applied, it is desirable that separate CT and VT inputs be used to achieve redundancy.

Integrating many protective functions into one package raises issues concerning reliability. This issue has been addressed in a number of ways. These include:

a) Partitioning protective functions into different microprocessors or different boards.
b) Providing different models, each with a portion of the protective functions. Redundancy may be available for some functions.
c) Providing backup for critical components, particularly the power supply.
d) Self-checking functions.

These measures all help to minimize the effect of a single component failure. Failure of an MGPS may require the generator be taken out of service. However, present industry practice provides at least two MGPSs for each protection application for a generator that cannot be taken out of service for a loss of a protective relay. In most cases, some type of redundant single function relay such as overall differential is applied in addition to the MGPS.

In the MGPS, self-test and diagnostics detect many failure modes and alert the user through alarm outputs. The ability to detect and correct a failure before the protection system needs to operate is a contrast to traditional protection where a relay failure would probably not be detected until the next maintenance test or until the relay false trips or fails to operate correctly during an event. For these reasons, most users apply a combination of the MGPS and discrete relays for generator protection.

As indicated earlier**,** factors such as the importance and size of the generator, manufacturer recommendations, and user’s experience will guide users in applying MGPSs.

Examples of implementing MGPSs include the following:

1) Complete backup by discrete component relays.
2) Selective backup of some functions.

3) Use of different protection functions from two different designs.
4) Sole reliance on one MGPS, with the unit shutdown initiated on the detection of critical failures within the protection system.

If two MGPSs are applied, then the user has a number of choices on what protection function to include in each MGPS. Some MGPSs provide full function protection for large or important generators. Other MGPSs provide reduced protective functions for smaller or less important generators. Some MGPSs also provide user configurable protective functions to meet the needs of the user. Users should take into account factors such as degree of redundancy required, oscillographic and communication capabilities, cost, training requirements, and preference for a particular design approach.

Figure 6-2 is an example of a large or important unit generator-transformer configuration with two MGPSs, applied with redundant protective functions. This figure shows both MGPSs with the same protection. However, the application of two MGPSs with different operating principles may improve the overall dependability of the protection scheme.

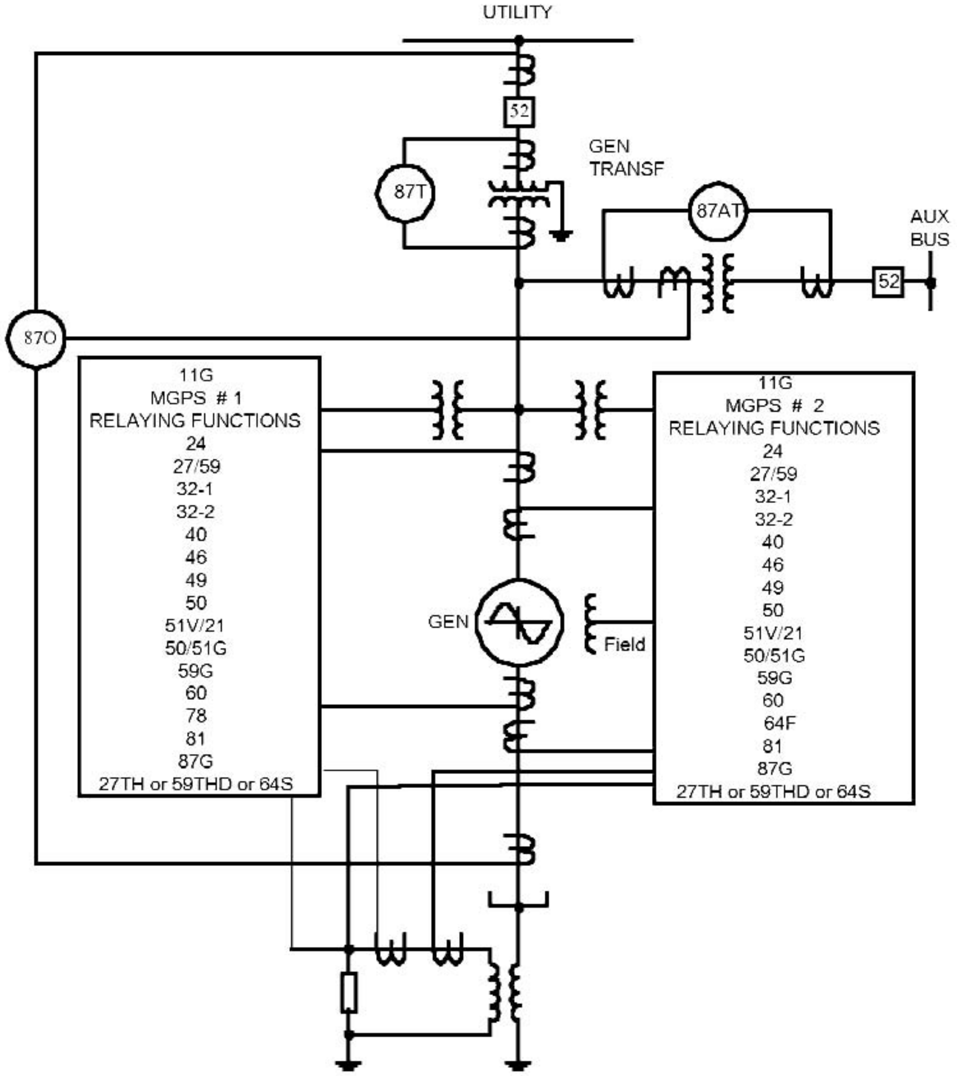


Figure 6-2—Typical protection for a large or important generator

NOTE—Most available functions in various MGPSs are shown in Figure 6-2. Actual functions available depend on a specific MGPS selected. Also, the inputs (CT, VT, RTDs, etc.) shown may vary depending on specific functions used.

Each of the MGPSs has its own separate dc-to-dc power supplies and tripping circuits. The built-in self-monitoring and diagnostic functions are always online and detect many relay failures, thereby reducing the likelihood of false operation. Periodic testing and preventive maintenance may be reduced to a minimum because only the items and responses not fully covered by the self-monitoring and diagnostic functions need to be checked. If provided, the status of each MGPS may be determined by the station control system by cyclically interrogating the diagnostic function via the communications link. This confirms that the self-monitoring system is working and the protection is available.

6.2.3 Protection function tripping schemes

The selection of a trip or alarm action produced by the operation of different protection functions varies by user, depending on the user's experience, philosophy, interpretation of standards, and turbine-generator manufacturer's recommendations. Many MGPSs allow the user the flexibility to route any individual protective function output to selected trip or alarm relay outputs. This design allows the trip scheme and logic to be configured for redundant trip paths so as to eliminate single-contingency failures of the trip relay. Additionally, this trip logic enables the user to consider the generator and prime mover's operational capabilities (type of prime mover, system configuration, regulator response, boiler and governor control systems) to avoid unnecessarily stressing the unit. Four methods of isolating a unit are discussed in Clause 7 that should be considered when applying an MGPS: simultaneous tripping, generator tripping, unit separation tripping, and sequential tripping.

The trip scheme shown in Figure 6-2 employs more than one lockout relay (86) because different conditions dictate different types of tripping. Conditions such as generator and main transformer faults require the immediate simultaneous tripping of the generator circuit breaker(s), field circuit breaker, and prime mover so as to minimize damage to the unit and disturbance to the system. Operating functions, such as negative-sequence current or abnormal frequency, require separation of the generator from the system, but not necessarily tripping of the field circuit breaker or prime mover. Therefore, unit separation tripping may be appropriate. The reverse power function is shown as part of sequential tripping control logic. In this example, generator tripping is initiated by a combination of the reverse power function contact in conjunction with the turbine trip indication. Other functions, such as thermal protection, may necessitate only operator action and therefore may alarm. The user should evaluate each function with its impact on the equipment and system before determining the trip logic. This should also be discussed with the turbine-generator manufacturer.

Figure 6-3 shows the implementation of tripping logic for the protection of a unit-transformer configuration using MGPSs. The use of two MGPSs allows further flexibility in tripping logic configuration by eliminating common mode failures, thus allowing greater dependability. Initiating different lockout relays for the same function, such as the generator differentials on each MGPS, is an example of greater dependability. Initiating those same lockout relays, one with a generator neutral ground overvoltage function (59G) from one MGPS and the other MGPS with a generator neutral ground overcurrent function (50/51G), is an example of providing redundant protection using alternative functions as a means of improving dependability.

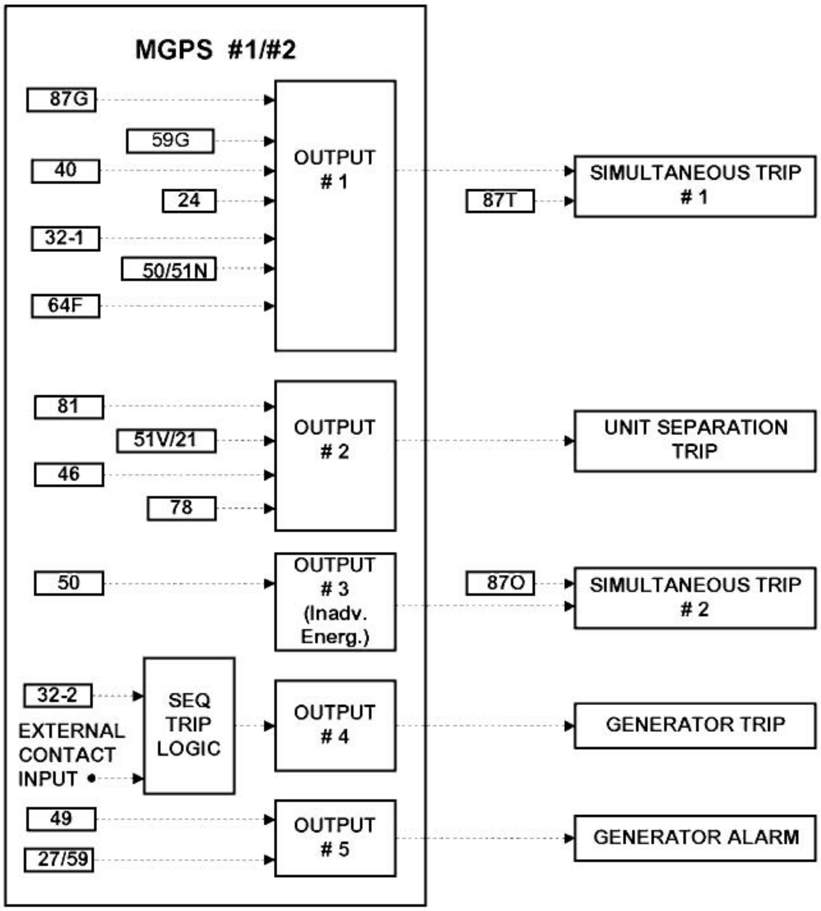


Figure 6-3—Typical tripping configuration for a large or important generator

6.3 Testing of MGPSs

6.3.1 Evaluation Testing

Evaluation testing by the user or by a third party provides demonstrated background and understanding of the functions and performance of the MGPS. This optimizes the utilization of the MGPS, in that the understanding gained from the tests helps determine the requirements for acceptable dependability (i.e., what functions, if any, should be duplicated) and the applicable commissioning and maintenance procedures.

6.3.2 Acceptance testing

Many users subject all relays to acceptance testing. With an MGPS, consideration should be given to reducing the number of tests by designing the test program to test the integrity of each of the necessary hardware components, rather than each of the relaying functions (overvoltage, reverse power, loss of field, etc.). Evaluation testing as previously described may serve to define the desirable complement of tests. Also, in the interest of producing an acceptance plan that is both efficient and thorough, the user may wish to look to the (MGPS) protection system manufacturer for guidance, based on their intimate knowledge of the MGPS design.

6.3.3 Commissioning and maintenance testing

Because the different functions in the MGPS operate on the same set of voltages and currents and programmable logic available for output tripping, commissioning tests on external wiring and trip circuits are simplified. Moreover, because each function shares the analog inputs, testing of the individual relay functions for a given set of settings is easier to set up and perform than if these functions were in discrete relays. However, since more than one function may operate for a given set of test parameters, and many functions operate the same output contact, it may not be easy to identify which relay element has operated to close the output contact.

There are several ways to deal with this situation:

1) Some MGPSs provide test mode in which only a selected function under test operates test output contact to facilitate testing of individual functions.
2) Design the test inputs and sequence so that only one function will operate for a given set of test inputs.
3) Use the MGPS event report as an adjunct to the output contact closure.
4) Temporarily reprogram the output to an isolated contact.

Some users will object to the fourth method, since a large part of testing an MGPS is to check its programming. The second method requires some planning, and the proper test equipment. Combining the second and third methods likely will produce a test plan that avoids confusion as to which relay function has caused a trip. Some considerations in selecting the test parameters include:

a) Test functions such as V/Hz, overvoltage, and abnormal frequency with no current applied, so that the current and impedance functions will not operate.
b) Test V/Hz at less than nominal frequency, so that its pickup will be below the setting of voltage and frequency relays.
c) Test distance, power, and loss-of-field functions with currents applied to both phase and neutral side inputs so that the differential function will not operate.

The commissioning tests discussed above may be the result of a task in the evaluation tests discussed previously. Furthermore, periodic maintenance testing may be a subset of the commissioning tests. The maintenance tests should at least verify the proper functioning of all the input and output circuits. Some MGPSs provide test access for injecting voltage and current signals for maintenance testing. In deciding the frequency of maintenance testing, self-diagnostic features have justified reduction in the frequency of testing. However, certain caution is also justified as self-diagnostic features do not test the logic or the outputs, the failure of which, in the case of an MGPS, have a larger impact than that of a single function relay.

7. Protection specification

This clause presents detailed protective arrangements for six generating station configurations. There is a one-line diagram for each station configuration. A typical control logic diagram for the unit generator-transformer connection illustrates the combination of protective relays, with their control functions, normally applied in accordance with good engineering practices. The intent of these diagrams is to illustrate one approach for providing protection. The reader may modify the protection provided to meet the particular protective philosophy and reliability requirements. While it is generally agreed that the unit is tripped, steam system is shutdown, and auxiliaries are transferred for internal electrical faults, there is no generally agreed on approach for condition items such as V/Hz underfrequency, etc. See IEEE Std 502 for further discussion.

The protection of CTGs is quite similar to the protection of steam turbine generators. There are, however, certain differences in the design and application of CTGs that may result in different protection requirements. Since many CTGs are unmanned stations, control systems provide automatic protection. Figure 7-6 shows the recommended protection for a CTG.

7.1 Protective arrangements

The protective arrangements for the various generating station configurations are illustrated in the following figures:

Figure 7-1a—Protection for a unit generator-transformer configuration

Figure 7-1b—Protection for a unit generator-transformer configuration dc tripping logic

Figure 7-2—Protection for a unit generator-transformer configuration with dual generator breakers

Figure 7-3—Protection for cross-compound steam turbine generators

Figure 7-4—Protection for generators sharing a step-up transformer

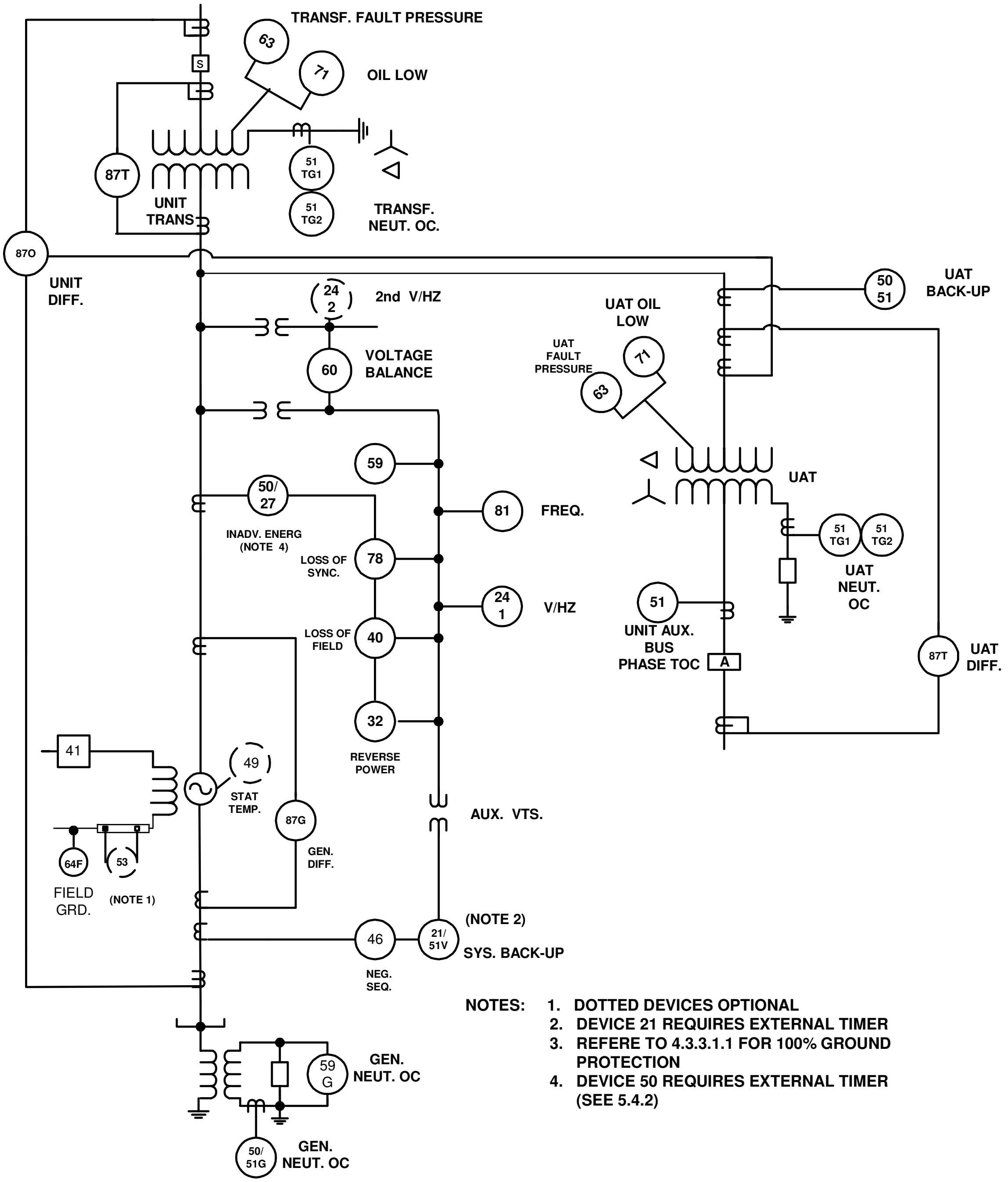
Figure 7-5—Protection for generators connected directly to a distribution system

Figure 7-6—Protection for combustion turbine generators

A number of factors will determine the selection of a protective scheme for 100% stator ground, generator breaker failure, and inadvertent energizing. To simplify the one-lines, examples of these schemes were not shown. These protective functions should be applied after considering factors described in the following related subclauses:

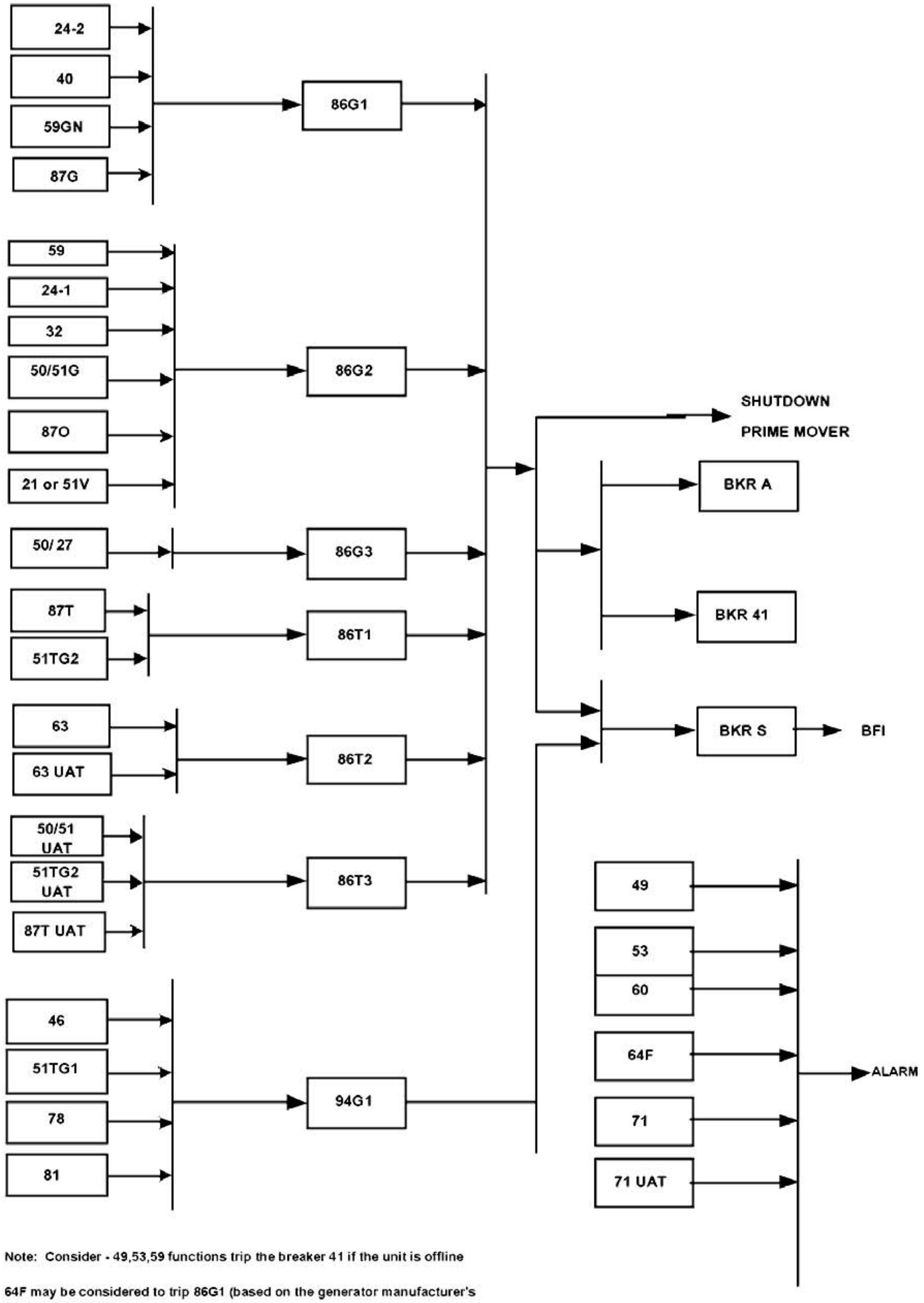
a) 100% stator ground (see 4.3.3.1.1)
b) Generator breaker failure (see 4.7)
c) Inadvertent energizing (see 5.4)

Due to space restrictions, the figures do not incorporate external timers in all cases. Refer to appropriate subclauses within the guide for timer applications.



NOTES:
1. DOTTED DEVICES OPTIONAL
2. DEVICE 21 REQUIRES EXTERNAL TIMER
3. REFERE TO 4.3.3.1.1 FOR 100% GROUND PROTECTION
4. DEVICE 50 REQUIRES EXTERNAL TIMER (SEE 5.4.2)

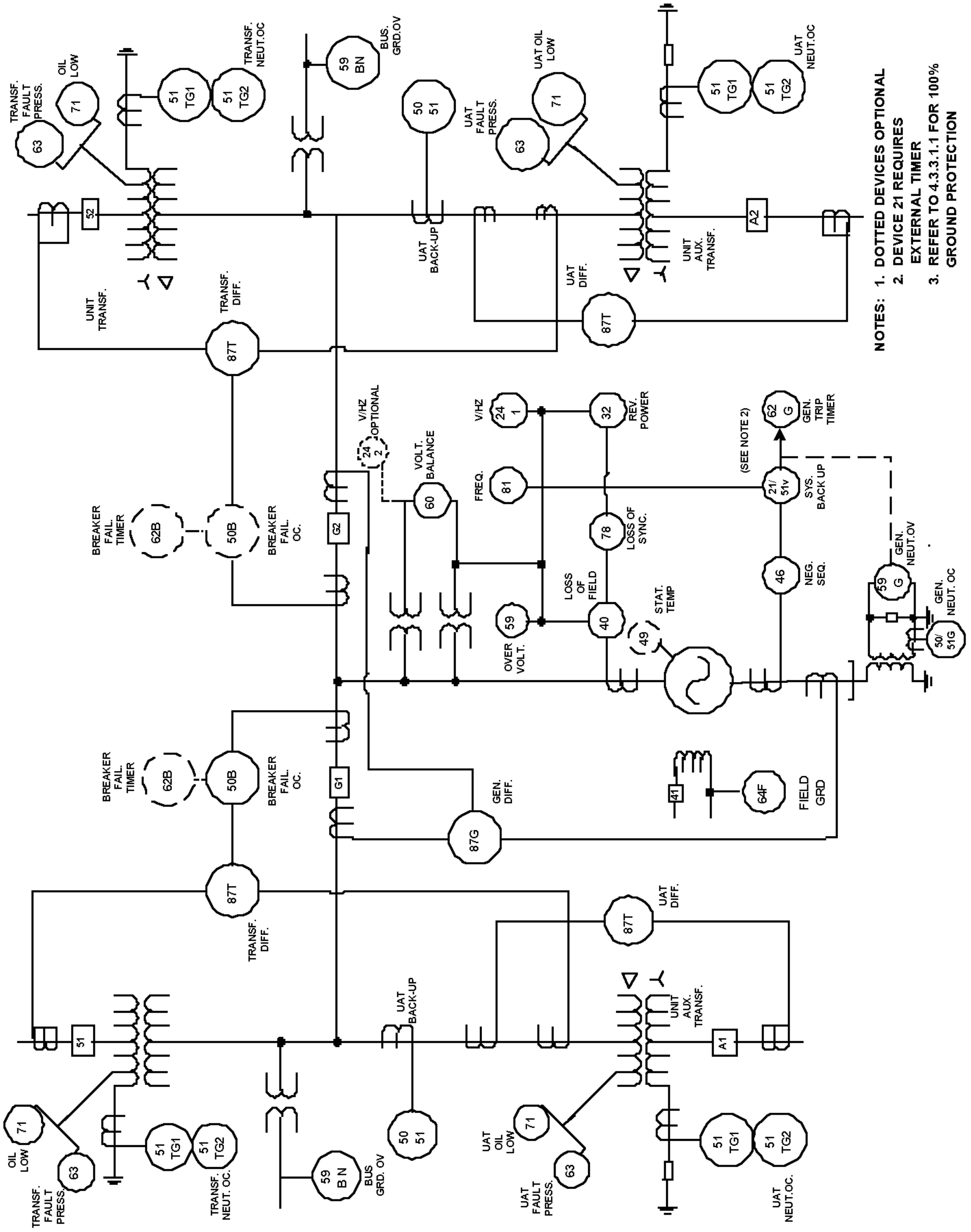
Figure 7-1a—Unit generator-transformer configuration



Note: Consider - 49,53,59 functions trip the breaker 41 if the unit is offline

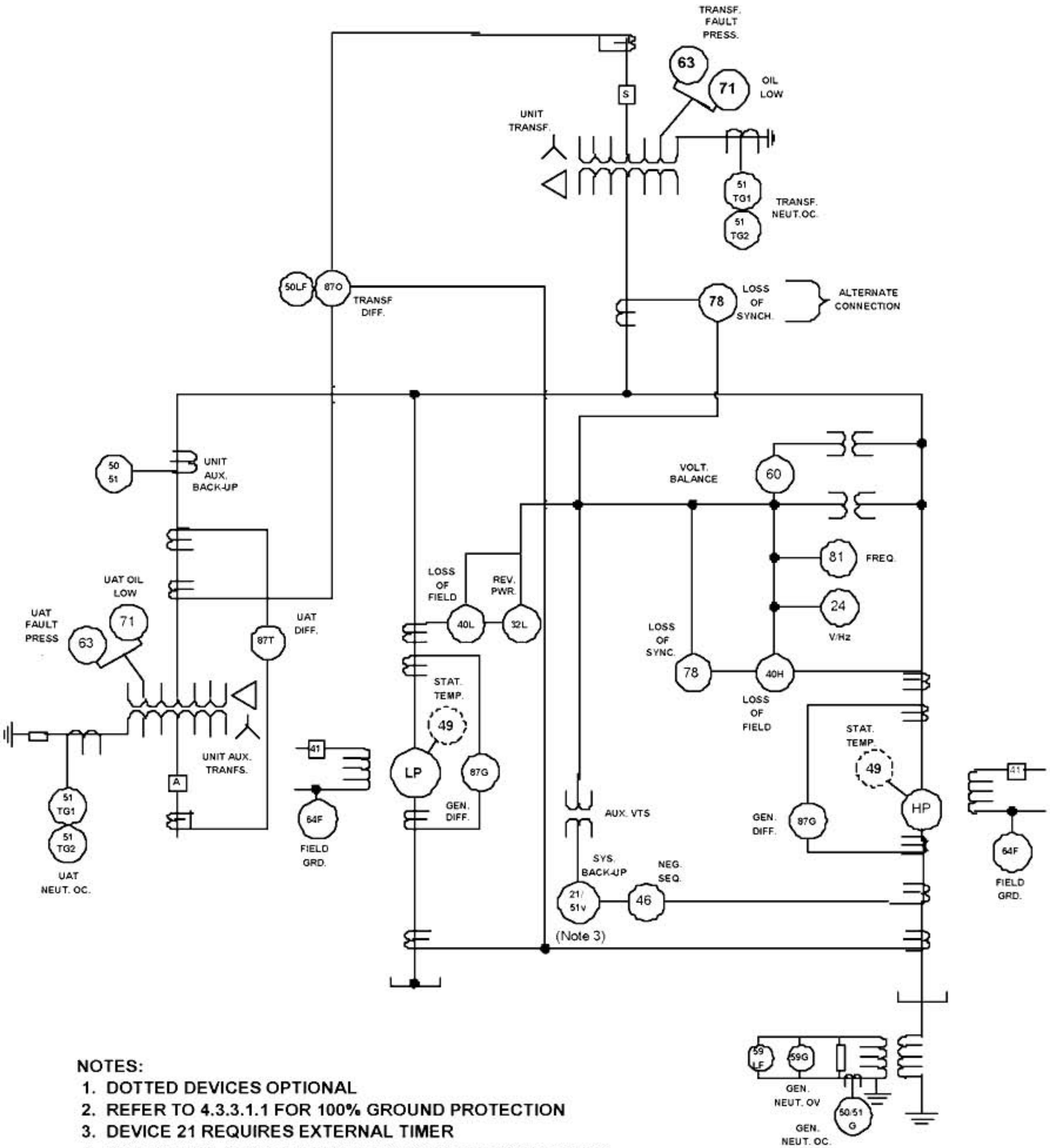
64F may be considered to trip 86G1 (based on the generator manufacturer's recommendation)

Figure 7-1b—Unit generator-transformer configuration dc tripping logic



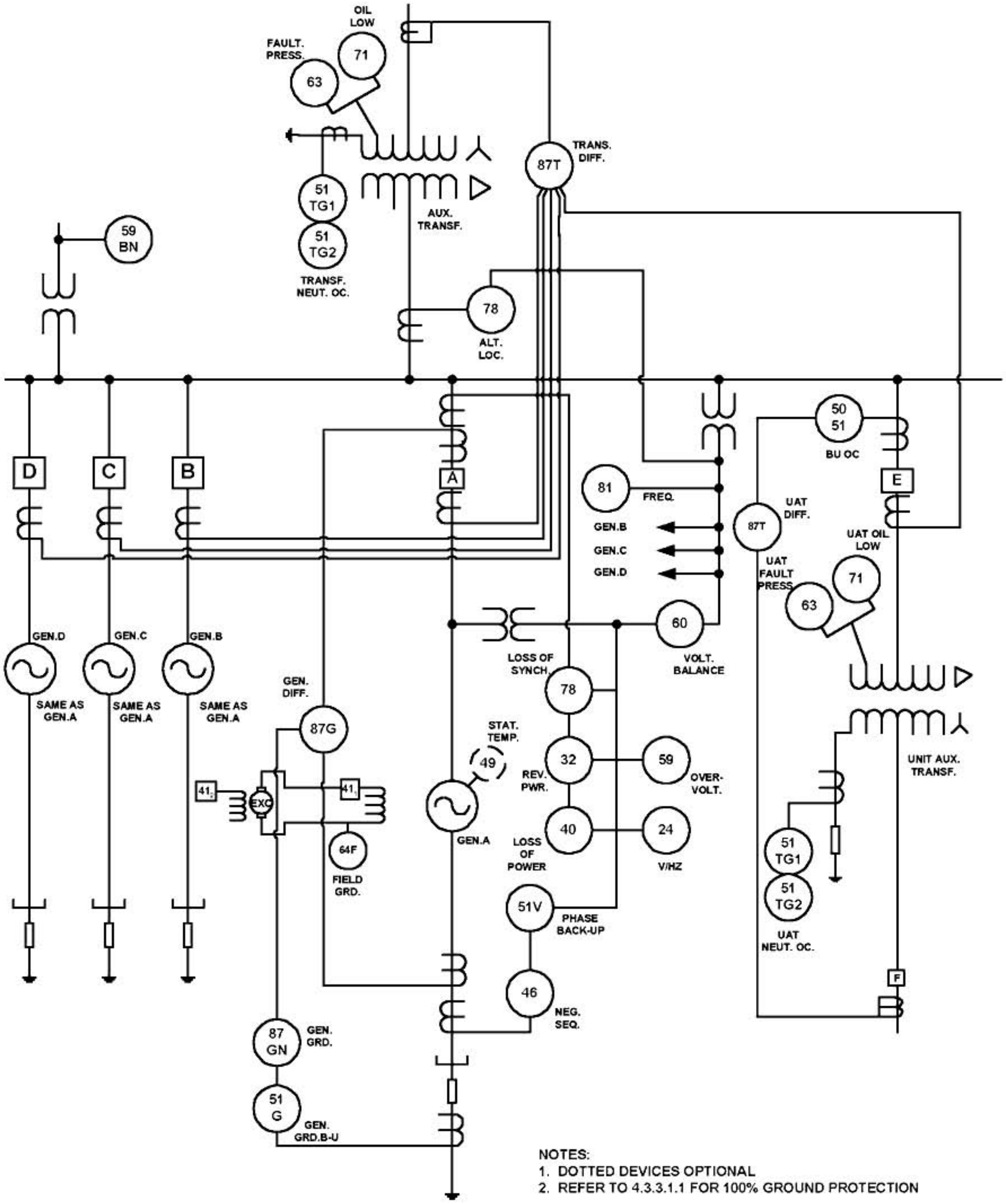
NOTES: 1. DOTTED DEVICES OPTIONAL
2. DEVICE 21 REQUIRES EXTERNAL TIMER
3. REFER TO 4.3.3.1.1 FOR 100% GROUND PROTECTION

Figure 7-2—Unit generator-transformer configuration with dual generator breakers



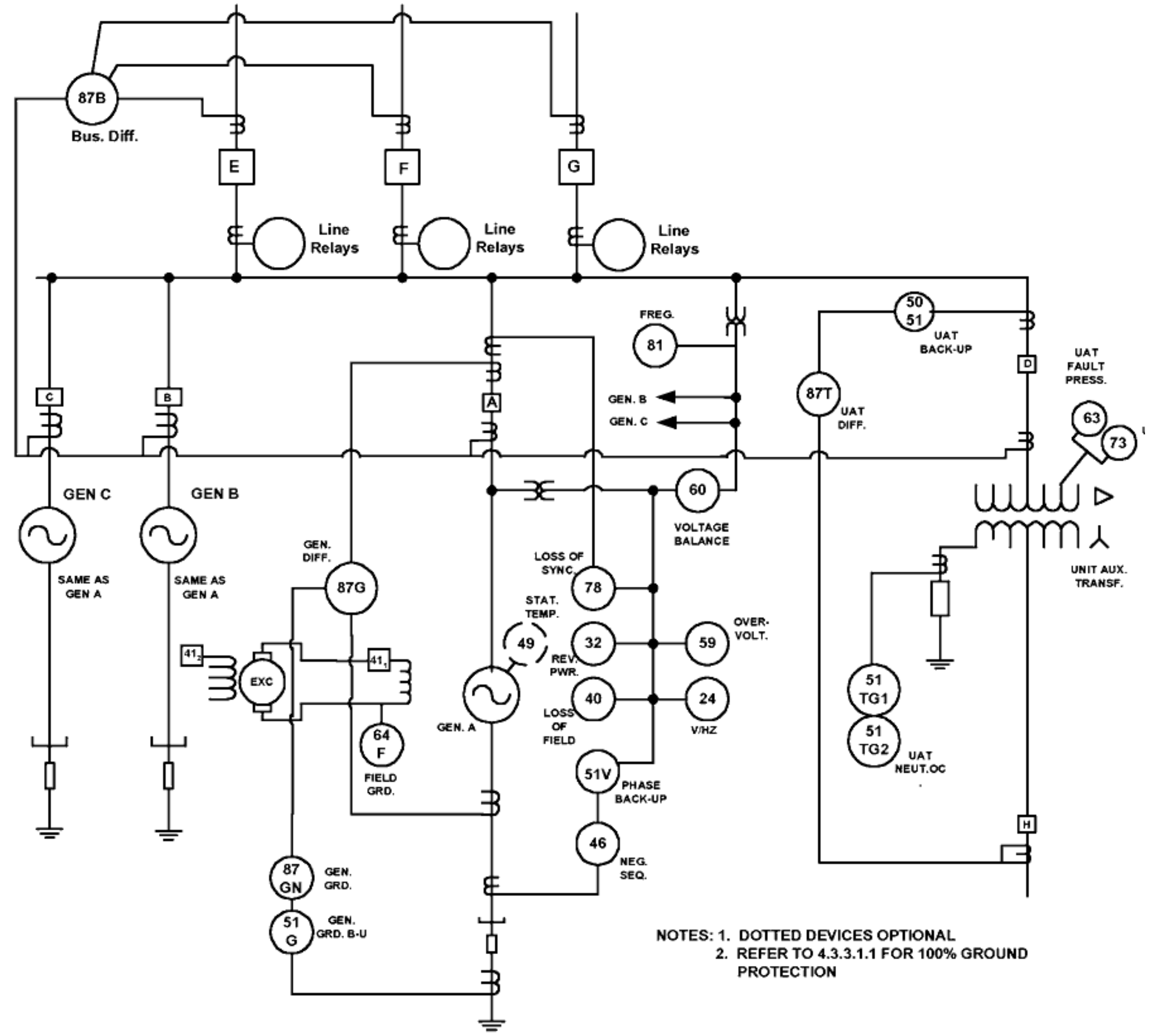
NOTES:
1. DOTTED DEVICES OPTIONAL
2. REFER TO 4.3.3.1.1 FOR 100% GROUND PROTECTION
3. DEVICE 21 REQUIRES EXTERNAL TIMER
4. 50LF ARMED AFTER TIME DELAY WHEN BREAKER OPENS
5. 50LF IS DESIGNED TO OPERATE DOWN TO LOW FREQUENCIES

Figure 7-3—Cross-compound generators



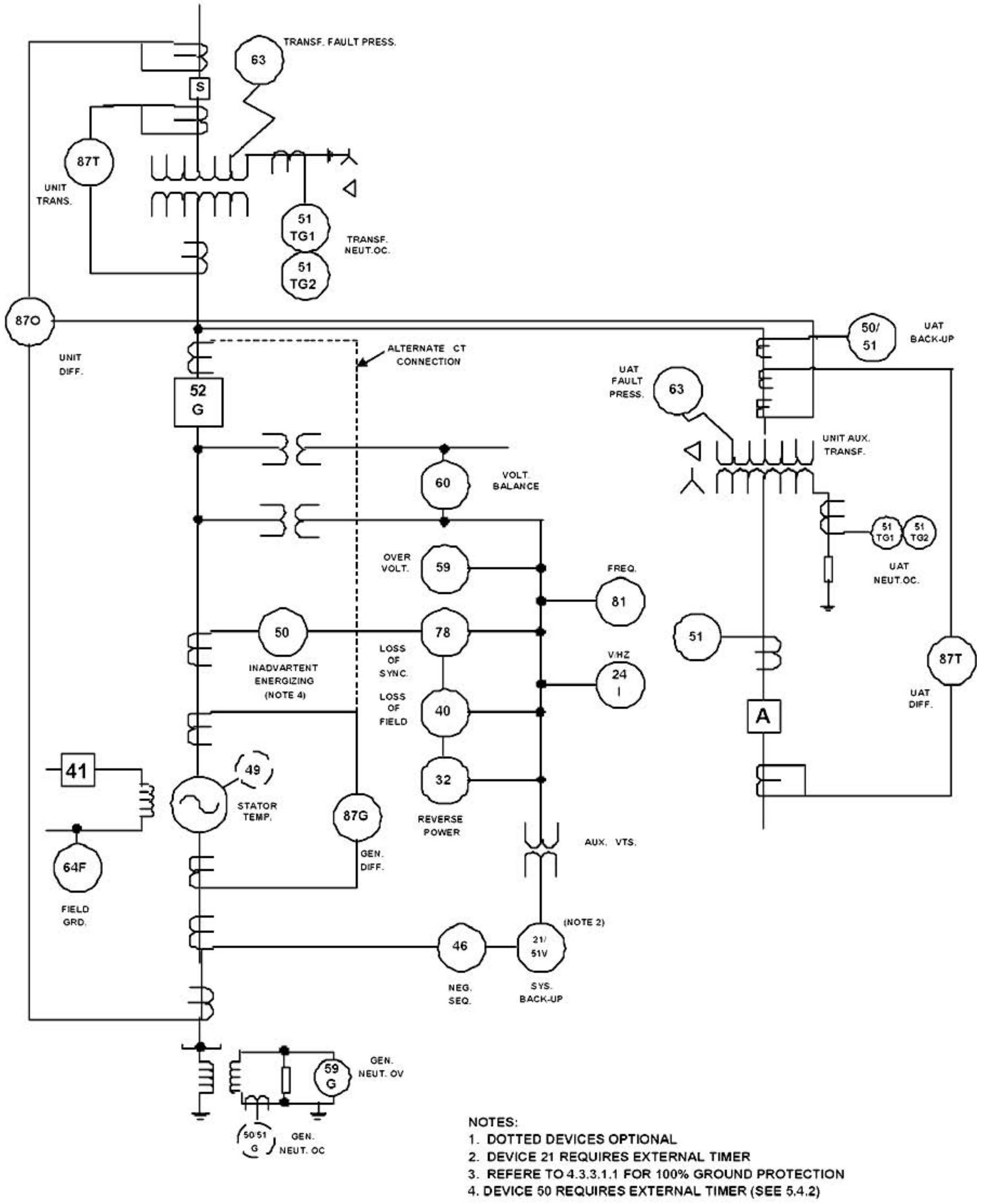
NOTES:
1. DOTTED DEVICES OPTIONAL
2. REFER TO 4.3.3.1.1 FOR 100% GROUND PROTECTION

Figure 7-4—Protection for generators sharing a unit transformer



NOTES: 1. DOTTED DEVICES OPTIONAL
2. REFER TO 4.3.3.1.1 FOR 100% GROUND PROTECTION

Figure 7-5— Protection for generators connected directly to a distribution system



NOTES:
1. DOTTED DEVICES OPTIONAL
2. DEVICE 21 REQUIRES EXTERNAL TIMER
3. REFERE TO 4.3.3.1.1 FOR 100% GROUND PROTECTION
4. DEVICE 50 REQUIRES EXTERNAL TIMER (SEE 5.4.2)

Figure 7-6—Protection for combustion turbine generator

7.2 Protective functions

The protective functions noted in the various generating station configurations provide both primary and backup protection for the generating station as well as additional protection schemes that could also be applied. These protective functions are listed in Table 7-1, with a reference to the subclause in the text that discusses their application in detail. Also included is a discussion of the various tripping modes used in generating stations.

7.2.1 Protective devices

Table 7-1—Protective devices

Device	Function	Subclause
11G	Multifunction generator protection system (MGPS).	6.2.3
21	Distance relay. Backup for system generator zone phase faults. Device 21 requires a time delay for coordination.	4.6.1
24	V/Hz protection for the generator.	4.5.4
27	Undervoltage relay.	4.5.7
27TH	Instantaneous undervoltage relay tuned to the third harmonic frequency.	4.3.3.1.1
50/27	Inadvertent energizing protection using voltage supervised overcurrent relaying.	5.4.2.4
32	Reverse power relay. Motoring protection.	4.5.5
40	Loss-of-field protection.	4.5.1
46	Stator unbalanced current protection. Negative-sequence relay.	4.5.2
49	Stator thermal protection.	4.1
50BF	IOC relay used as CD in a breaker failure scheme.	4.7
50/51	Time current relays with instantaneous element. High-side bank overcurrent relays providing phase fault protection for UAT and backup protection for failure of UAT low-side bank breaker.	
50G/51G	Time-overcurrent relay with instantaneous element. Primary and/or backup protection for generator ground faults.	4.3.3.1.1
51	Time-overcurrent relay. Detection of turn-to-turn faults in generator windings.	4.3.2
51TG1	Time-overcurrent relay. Provides backup protection for transmission ground faults when applied to GSU neutral. Protects for ground faults on the unit auxiliary bus when applied to UAT neutral.	4.6.2, 4.6.4
51TG2	Time-overcurrent relay. Provides backup protection for GSU ground faults when applied to GSU neutral. Protects for faults in the low side of the UAT down to the low-side bank breaker when applied to UAT neutral. Provides backup for failure of low-side breaker to trip.	4.6.2, 4.6.4
51 UAT	Time-overcurrent relays connected to CTs in UAT low-side bank breaker. Protects for phase faults on unit auxiliary bus.	
51V	Voltage controlled or voltage-restrained time-overcurrent relay. Backup for system and generator zone phase faults.	4.6.1.2
53	Exciter or dc generator relay.	4.5.4.5

Table 7-1—Protective devices *(continued)*

Device	Function	Subclause
59	Overvoltage protection.	4.5.6
59BN	Zero-sequence overvoltage relay. Ground fault protection for an ungrounded bus.	4.3.3.1.1
59N	Zero-sequence voltage relay, stator winding turn-to-turn fault protection.	4.3.2.5.2
59G	Voltage relay. Primary ground fault protection for a generator.	4.3.3
59TH	Instantaneous overvoltage relay tuned to the third harmonic frequency.	4.3.3.1.1
59THD	Instantaneous third harmonic voltage differential relay.	4.3.3.1.1
60	Voltage balance relay. Detection of blown potential transformer fuses.	5.2.1.1
62B	Breaker failure timer.	4.7
63	Fault pressure relay. Detects transformer faults.	4.9.2
64F	Voltage relay. Primary protection for rotor ground faults.	4.4
64S	100% stator ground fault protection with subharmonic voltage injection.	4.3.3.1.1
67N	Directional ground overcurrent relay.	4.3.3.2.1
71	Transformer oil or gas level.	4.9.1
78	Loss of synchronism protection. This protection is optional. Applied when, during a loss of synchronism, the electrical center is in the step-up transformer or in the generator zone. Alternate locations are shown for this protection. A study should be made to determine which location is best for the detection of an out-of-step condition.	4.5.3
81	Frequency relay. Both underfrequency and overfrequency protection may be required.	4.5.8
86	Hand-reset lockout auxiliary relay.	
87B	Differential relay used for bus protection.	
87G	Differential relay. Primary phase fault protection for the generator.	4.3.2
87GN	Differential relay. Sensitive ground fault protection for the generator.	4.3.3.2
87T	Differential relay. Primary protection for the GSU or UAT transformer. May be used to provide phase fault backup for the generator in some station arrangements. The zone may be extended to cover the generator bus using CTs from the generator and UAT when low side CTs are not available.	
87O	Differential relay for overall unit and transformer.	4.3.2.6
94	Self-reset auxiliary tripping relay.	

7.2.2 Tripping mode

Table 7-2 and Figure 7-1a are an example of the trip logic for protective devices on a unit generator-transformer as shown in Figure 7-1a. It provides guidance in developing a generator protection trip scheme. Individual trip scheme logic will vary, dependent upon the owner's preference and the capabilities of the prime mover.

Where possible, the arrangement of the lockout relays should provide redundancy in both trip paths and trip functions, so that backup relays trip a separate lockout relay from the primary protection. The task associated with applying tripping schemes on generating units should not be underestimated. This effort requires a broad knowledge of the generating unit equipment and its behavior during both normal and abnormal conditions. It would be shortsighted if the only consideration given is to disconnect the generator from the electrical system without taking into consideration the precise manner in which the generating unit may be isolated from the power system for various protective relay operations.

Many factors contribute to the decision on the selection of the appropriate tripping scheme. Following are several key items:

1) Type of prime mover—diesel/gas engine, gas turbine, steam turbine, or waterwheel.
2) Impact of the sudden loss of output power on the electrical system.
3) Safety to personnel.
4) Operational experience.
5) Management of unit auxiliary loads during emergency shutdown.
6) Extent of damage or potential damage due to the fault or abnormality.

Following are four common methods for isolating the generator from service following unacceptable abnormal operating conditions or electrical faults.

7.2.2.1 Simultaneous tripping

This provides the fastest means of isolating the generator. This tripping mode is used for all internal generator faults and severe abnormalities in the generator protection zone.

Table 7-2—Trip table

Device	Generator breaker trip	Field breaker trip	Transfer auxiliaries	Prime mover trip	Alarm only	Subclause reference
21 or 51V	X	X	X	X		4.6.4
24	X	See Note 2	X	See Note 11		4.5.4.4
32	X	X	X	X		4.5.5.6
40	X	X	X	See Note 11		4.5.1.4
46	X	See Note 7	See Note 7	See Note 7		4.5.2.2
49					X	4.1
50/27 (See Note 10)	X	X	X	X		5.4
50/51G	X	X	X	X		4.3.3.1.2
51TG1	X					4.6.4
51TG2	X	X	X	X		4.6.4
51TG1 UAT	See Note 6	See Note 6	See Note 5	See Note 6		
51TG2 UAT	X	X		X		
50/51 UAT	X	X	See Note 5	X		

Table 7-2—Trip table *(continued)*

Device	Generator breaker trip	Field breaker trip	Transfer auxiliaries	Prime mover trip	Alarm only	Subclause reference
53		See Note 2			X	4.5.4.5
59	X	X	X	See Note 13	See Note 1	4.5.6.2
59G (See Note 9)	X	X	X	X	See Note 3	4.3.3.1.2
60					X	5.2.1
63	X	X	X	X		4.9.2.2
63 UAT	X	X	X	X		
64F	See Note 4	See Note 4			X	4.4.2
67N	X	X	X	X		4.3.3.1.2
71					X	4.9.1
71 UAT					X	
78	X	See Note 8	See Note 8	See Note 8		4.5.3.4
81	X					4.5.8.4
87G	X	X	X	X		4.3.2.7
87T	X	X	X	X		4.3.2.7
87T UAT	X	X	X	X		
87O	X	X	X	X		4.3.2.7

NOTE 1—Device 59 may be connected to alarm only on some units.

NOTE 2—If generator is off-line, trip only field breaker.

NOTE 3—Refer to 4.3.3.1.2.

NOTE 4—May be connected to trip, per generator manufacturer.

NOTE 5—Trips unit auxiliary bus incoming breaker (Breaker A, Figure 7-1a).

NOTE 6—If tripping of Breaker A results in loss of auxiliaries, these trips are required and 51TG2/UAT is not required.

NOTE 7—Refer to 4.5.2.2 on unbalanced currents.

NOTE 8—Refer to 4.5.3.4.

NOTE 9—27TH, 59TH, 59THD, 64S trip table is similar to 59G.

NOTE 10—50/27 function uses voltage supervised overcurrent relaying for inadvertent energizing protection. Other protection functions described in 5.4 use the same trip logic.

NOTE 11—Refer to 4.5.4.4.

NOTE 12—Refer to 4.5.1.4.

NOTE 13—Refer to 4.5.6.2.

Isolation is accomplished by tripping at the same time the generator breakers, field breaker, and shutting down the prime mover by closing the turbine valves.

Auxiliary loads are transferred to a standby source. If there exists a potential for significant overspeed condition of the unit, a time delay may be used in the generator breaker trip path. If time delay is used, the effect of this delay on the generator and/or system should be determined.

7.2.2.2 Generator tripping

This mode of isolation trips the main generator and field breakers. The scheme does not shut down the prime mover and is used where it may be possible to correct the abnormality quickly, thereby permitting the reconnection of the machine to the system in a short period of time. This protection trips the generator for a power system disturbance, rather than an internal generator fault/abnormality. This mode may be used if permitted by the type of prime mover, boiler, and governor control systems and requires that the unit be capable of quick response following a load rejection.

7.2.2.3 Unit separation tripping

A variation of the generator tripping scheme is one where only the main generator breakers are opened. It is recommended for applications when it is desirable to maintain the unit auxiliary loads connected to the generator. The advantage of this scheme is that the unit may be reconnected to the system with minimum delay. As with the generator tripping scheme, the unit needs to be capable of a quick response following a load rejection.

7.2.2.4 Sequential tripping of steam turbine generators[9]

As power plant unit sizes increased and feedwater/steam cycles became complicated, the shutdown process for steam turbine generating units became more critical. These issues made a more orderly shutdown of the turbine generator desirable, if not a requirement. The traditional practice of tripping the main unit breakers immediately following a boiler/turbine trip could needlessly expose the unit to a potentially catastrophic overspeed condition and other unnecessary stresses.

There are several reasons for the increase in importance of the shutdown process. Most unit trips are the result of boiler and turbine mechanical problems rather than problems in the generator and associated high-voltage equipment. The introduction of refined turbine blading designs that, while more efficient, are not as rugged as earlier, simpler blade designs and are not able to withstand overspeeds much higher than 120% of rated speed. Finally, given the added complexity of multiple steam admission paths with the associated stop and control valves, it is more difficult to insure the complete shutoff of steam flow to the various turbine sections.

The purpose of sequentially tripping a turbine generator is to minimize the possibility of damaging the unit as a result of an overspeed condition following the opening of the main generator breaker(s). This method is also commonly used as the normal shutdown mode for many units with different types of prime movers. This method of isolating the unit from the power system is used for operating conditions where delayed tripping of the generator will not result in increased damage to electrical equipment. Sequential tripping is accomplished by first tripping the prime mover (turbine) followed by tripping the generator and field breakers after a brief period of deliberate motoring to ensure that all residual driving power is drained off of the turbine.

Turbine generator manufacturers have indicated that the overspeeding of a turbine generator is a more damaging operating condition than a brief motoring of the unit. A brief period of deliberate motoring to

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[9] See IEEE/PSRC Working Group Report [B23].

reduce the likelihood of excessive overspeed will not cause damage to the turbine. Manufacturers have incorporated this philosophy into their sequential tripping recommendations.

Designers and operators of power plants today should be concerned with the failure of control and protective devices to operate, the failure of a breaker to trip, protective devices out of service, and operator error. For these reasons, backup protection and supervisory devices are critical for any sequential tripping scheme.

Sequential tripping of a unit may be initiated by either a plant operator, boiler/reactor trip, or turbine-generator mechanical problem. Normal unit shutdowns may be accomplished safely and automatically simply by an operator initiating a boiler/turbine trip. This additional tripping mode provides another choice of action between an “alarm-only” indication and a simultaneous tripping mode.

Abnormal operating conditions, which do not require immediate generator shutdown, could be set to initiate a sequential trip. These include most abnormal mechanical conditions, but they could also include some electrical conditions.

Sequential tripping schemes designed for normal shutdown conditions and for mechanical trips such as boiler or turbine initiated trips would need to be reviewed under unit islanding conditions. For example, these conditions may occur when only the high-voltage generator breaker is tripped and the generator is feeding its own auxiliaries. Sequential trip schemes trip turbine first and on reverse power trip the generator field breaker. However, during an island condition, the sequential tripping scheme would not be effective, as there is no reverse power condition to trip the generator. Therefore, under islanding conditions, another function should be used to provide the trip instead of reverse power. One method would be to enable the underfrequency protection during islanding conditions.

Figure 7-7 shows the sequential tripping control logic scheme. A mechanical device indicating a “turbine tripped” condition, supervised by an electrical reverse power relay, initiates the shutdown of the generator and the transfer of unit auxiliary busses to a standby power source. It is important to remember that these devices are part of the control logic and are not performing a protective function.

7.2.2.4.1 Performance of reverse power relay for sequential tripping

By definition, a generating unit is motoring when real power flows into the generator from the power system. The generator performs as a motor, driving the turbine. Power required to motor depends upon the friction and windage losses of the steam turbine generator, typically in the range of 0.5% to 3% of rated generator power output. A sensitive electrical relay, which may detect reverse power flow into the unit, is the best means of detecting a motoring condition.

Since it may not be possible to set the mechanical devices to accurately measure the point where power flows into the machine, it is recommended that a reverse power relay be installed. The reverse power relay should have the necessary sensitivity to detect a reverse power condition and incorporate sufficient time delay to avoid nuisance tripping. It is typically set to pick up below machine rated motoring power, by a margin, to insure that there is not sufficient steam flow into the turbine to cause an overspeed when the generator breakers are opened.

A time delay is also used in the logic circuit to provide maximum security against a possible overspeed condition. Since permissible motoring times for most units are on the order of minutes, the additional time delay (typically 1 s to 3 s is recommended) will not increase the likelihood of equipment damage.

Should a main generator breaker fail to open in the sequential trip shutdown process, the generator will operate as an induction motor after the field breaker trips.

This type of operation may result in a severe local system voltage depression, and damaging currents may be induced in the generator rotor winding and body. To minimize this possibility, one may supervise the field breaker trip by using auxiliary “b” contacts from the generator breaker(s). Delayed tripping of the field breaker will not result in any additional damage to the unit. Breaker failure should be initiated by the sequential tripping scheme lockout as shown in Figure 7-7.

The performance of a reverse power relay is affected by the reactive power flow of the turbine generator during a motoring condition. Real power consumed by the motoring unit is extremely small compared to the unit’s continuous rating. The magnitude of var flow and resultant operating power factor for the motoring condition are determined by the level of generator excitation when the turbine is tripped.

If there is a small deviation from an ideal characteristic of the relay, a reverse power relay may fail to pick up under conditions of high machine var flow. As part of the sequential tripping procedure, it is recommended that the var output of the machine be reduced by control or operator action. In addition, operators should be alerted to the possibility of reverse power relays not operating and be trained in procedures to manually open the generator breaker after carefully checking that power flow is into the machine.

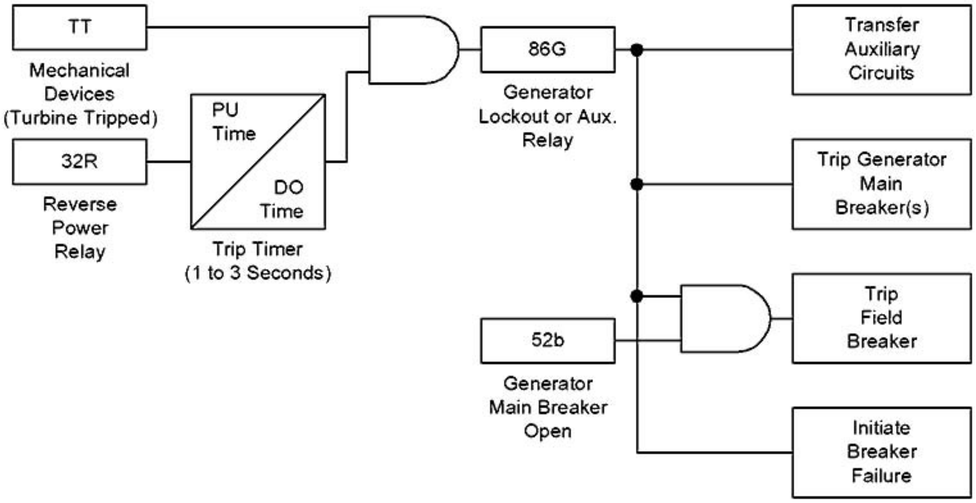

Figure 7-7— Sequential tripping control logic

7.2.2.4.2 Turbine trip backup protection

The main function of backup protection is to ensure that in the event of a failure of the sequential tripping scheme, the unit will be isolated from the power system. To the extent possible, backup protection should be applied independent of the primary tripping scheme, with as few common components as possible. Manufacturers use various electrical and mechanical protective devices to detect the failure to isolate the steam turbine generator from the power system following a turbine trip. Most turbine trip backup functions are performed by measuring or other means of determining when power is drawn from the power system and motoring the generator.

A reverse power relay is recommended as backup protection for excessive motoring of the unit. This reverse power relay will initiate either a simultaneous or generator trip, and it is set to be less sensitive or set at the same sensitivity with a longer time delay than the reverse power relay used in the sequential tripping control logic. Generally, this relay will be supervised by a “generator breakers closed” signal. The application of reverse power detection for backup protection should utilize a time delay. Typically 30 s may be used to prevent operation during power swings caused by system disturbances or when synchronizing the turbine generator to the system.

7.2.3 Other generator tripping considerations

In large power plants, it is common to use a breaker-and-a-half yard layout with a disconnect on the generator feed. This allows the generator to be taken off-line, the disconnect opened, and the breakers closed to maintain another tie between the main busses. In the early phases of plant construction, it is common to have a ring bus configuration that will later be expanded to a breaker-and-a-half. The ring configuration requires a disconnect switch on the generator feed that may be opened so that the ring may be closed when the generator is off-line. Some engineers have used auxiliary contacts in the motor operator of these disconnect switches to disable some or all of the generator protection when the generator is off-line. While this appears to be a convenient indication of the status of the machine, it may be fooled by abnormal conditions and should be avoided.

7.2.3.1 Maintenance

When the generator is off-line for maintenance, safety rules and procedures may require the generator potential transformers to be racked out and tagged. Also, in some instances, CTs may be shorted and even the station dc tripping source may be disconnected. The design engineer should be aware of these possibilities when determining the type and location of generator backup and inadvertent energizing protection. The common belief is that if the generator is off-line, the protection is not needed. However, generators have been inadvertently energized and there is therefore a need to provide as much protection as possible even when the machine is off-line. Refer to 5.4.

7.2.3.2 Disconnect switch

When protective relaying is routinely disabled with auxiliary contacts from the disconnect switch, the following should be carefully considered. Due to contamination, adjustment, and linkage problems the auxiliary contacts may not properly close and vital protection may be out of service when needed most. Also, if the auxiliary contacts are located inside the motor operator compartment, they may only follow the motor mechanism and not the actual switch blades. When the motor operator is uncoupled from the switch shaft and the switch is closed manually, the protection will be out of service. Even if the auxiliary stack is mounted so that it follows the disconnect switch operating shaft, it is not considered reliable. Several very serious accidents may be traced directly to using auxiliary contacts to disable protection and this practice is not recommended.

7.2.3.3 Potential sensitive relays

Underfrequency relays that depend on potential may misoperate during start-up if they are energized from the generator VTs. An alternative to using the disconnect switch auxiliary contacts to disable these relays is to use switchyard potential or start-up source potential. Electromechanical impedance type relays that use voltage for restraint may generally be adjusted so that there is sufficient spring restraint to keep the relays from misoperating during start-up.

7.2.3.4 Control schemes

Some control schemes use the disconnect switch auxiliary contacts to disable certain boiler trips while the machine is in start-up. This is fairly common on coal-fired units where it takes a long time to get the machine online. If a nuisance trip occurs, many hours may be wasted. While it is necessary to be sensitive to the control problems, the generator protection should not be compromised in the process.

Annex A

(informative)

Sample calculations for settings of generator protection functions

This annex describes the types of calculations that may be used in setting the majority of protection functions. The settings are calculated for a sample system. The generator and power system data are supplied by an electric utility company from an actual installation. The calculations shown here are for typical settings and are given only for the purpose of illustrating the steps involved in the setting calculations. Other setting methodologies or variations in the illustrated methodologies may be used. Consult with the equipment (turbine generator, excitation system, transformer, etc.) manufacturers and the relay manufacturers for additional guidance for your specific applications. It is important that certain generator protection settings be evaluated for their response to system disturbances to ensure proper protection and prevention of undesirable trips. Refer to IEEE/PSRC Working Group Report [B22].

A.1 Generator and power system data

The following one-line diagram (Figure A.1) shows the data for the generator, unit transformer, and connected power system power.

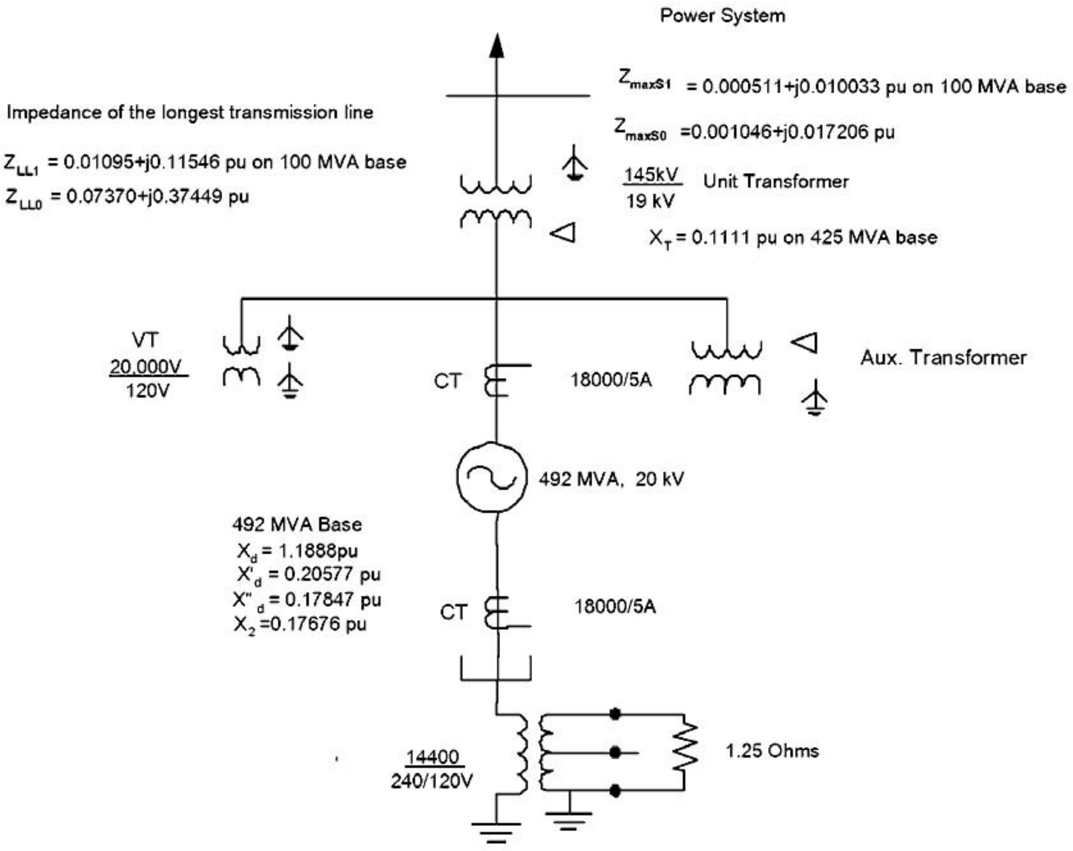

Figure A.1—One-line diagram with generator and power system data

A.1.1 Generator

492 MVA (MVA_G), 20 kV, 14 202 A, 0.77 pf, 3−phase, 60 Hz, 3600 RPM

Direct-cooled cylindrical synchronous generator and the prime mover is a steam turbine

Direct axis synchronous reactance (X_d) = 1.1888 pu

Saturated direct axis transient reactance ($X_d^{'}$) = 0.20577 pu

Saturated direct axis subtransient reactance ($X_d^{''}$) = 0.17847 pu

Negative-sequence reactance (X_2) = 0.17676 pu

VT ratio = 20 000/120 = 166.67 and CT ratio = 18 000/5 = 3600

VTs are connected Y-ground/Y-ground

A.1.2 Unit transformer

425 MVA (MVA_T), 145 kV/19 kV, Y-ground/Δ, 3−phase, 60 Hz, two winding

Leakage reactance X_T = 0.1111 pu on 425 MVA base

Transformer is set on 145 kV tap

A.1.3 Power system

All system impedances are given on 100 MVA (MVA_S) and 138 kV base.

Positive and zero-sequence impedances during maximum generation are:

$$Z_{\max S1} = 0.000511 + j0.010033 \text{ pu}$$

$$Z_{\max S2} = 0.001046 + j0.017206 \text{ pu}$$

Positive sequence impedance during minimum generation/weak system is:

$$Z_{\min 1} = 0.00105 + j\,0.016463 \text{ pu}$$

Positive and zero-sequence impedances of the longest transmission line connected to the unit transformer bus are:

$$Z_{LL1} = 0.01095 + j0.11546 \text{ pu and } Z_{LL0} = 0.07370 + j0.37449 \text{ pu}$$

Positive and zero-sequence impedances of the shortest transmission line connected to the unit transformer bus are:

$$Z_{SL1} = 0.00546 + j0.05773 \text{ pu and } Z_{SL0} = 0.03685 + j0.18725 \text{ pu}$$

A.1.4 Convert all data to generator base

Using generator MVA (MVA_G) and kV (kV_G) as the base, the transformer impedance is given by Equation (A.1):

$$X_{TG} = \frac{\mathrm{MVA}_G}{\mathrm{MVA}_T}\frac{\mathrm{kV}_T^2}{\mathrm{kV}_G^2}X_T \tag{A.1}$$

$$= 0.11607 \text{ pu}$$

Since the system base voltage is different from the transformer base voltage, it is necessary to first convert the system impedance values to the transformer base and then to the generator base, as shown in Equation (A.2).

$$Z_{\max ST1} = \frac{\mathrm{MVA}_T}{\mathrm{MVA}_S}\frac{\mathrm{kV}_S^2}{\mathrm{kV}_{THigh}^2}Z_{\max S1} \tag{A.2}$$

$$= 0.001967 + j0.038623 \text{ pu}$$

The positive sequence impedance of the power system (at maximum generation) on the generator base ($Z_{\max SG1}$) is given by Equation (A.3):

$$\mathrm{Z}_{\max SG1} = \frac{\mathrm{MVA}_G}{\mathrm{MVA}_T}\frac{\mathrm{kV}_{TLow}^2}{\mathrm{kV}_G^2}Z_{\max ST1} \tag{A.3}$$

$$= 0.002055 + j0.040352 \text{ pu}$$

Where MVA_S (base system MVA) is 100 MVA.

Using the preceding equations, the positive sequence impedance of the power system at minimum generation/weak system ($Z_{\min SG1}$) on the generator base is:

$Z_{\min SG1} = 0.00422 + j0.06621$ pu

Using the preceding equations, the positive sequence impedance of the longest transmission line (Z_{LLG1}) and the shortest transmission line (Z_{SLG1}) on the generator base is:

$Z_{LLG1} = 0.04404 + j0.46437$ pu

$Z_{SLG1} = 0.02196 + j0.23219$ pu

Figure A.2 shows the data for the generator, unit transformer, and the power system all on the generator base. The setting calculations will be simplified if the voltage, current, and impedances are converted to relay quantities (CT and VT secondary) as follows:

The generator VT primary base voltages are:

Line to line: 20 000 V

Line to ground: 20 000/√3 = 11547 V

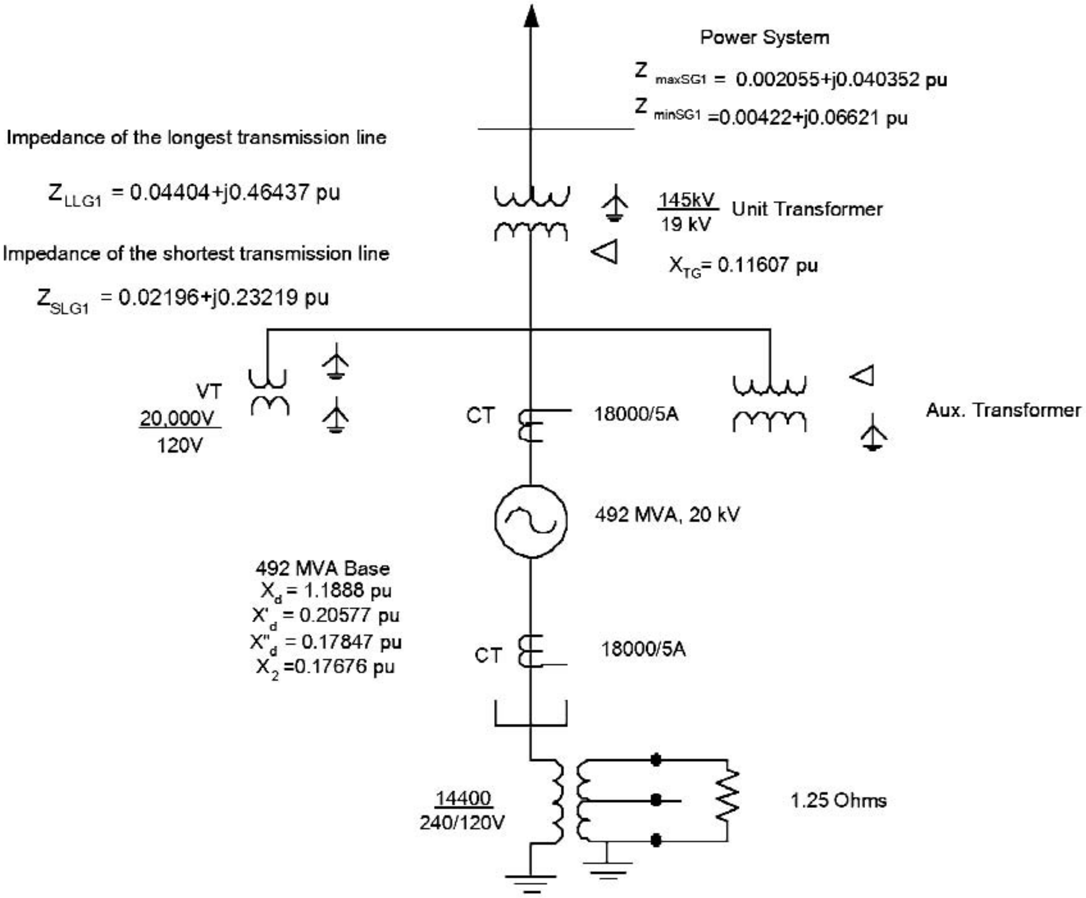

Figure A.2—One-line with data on generator base

The base voltages for the relay (or generator VT secondary) are:

$V_{LL\_B\_relay}$ = VT primary voltage/VT ratio = 20 000/166.67 = 120 V

$V_{LN\_B\_relay}$ = 11547/166.67 = 69.28 V

The generator CT primary line base current is 14 202.8 A. Thus, the base current for the relay (or CT secondary) is given by:

I_{B_relay} = CT primary current/CT ratio = 14 202.8/3600 = 3.945 A

The base impedance based on the relay secondary quantities is given by Equation (A.4):

$$Z_{B\_relay} = \frac{V_{LN\_B\_relay}}{I_{B\_relay}} = 69.28/3.95 = 17.56\ \Omega \tag{A.4}$$

A.2 Sample calculations for setting protection functions

A.2.1 Loss of field (40)[10]

There are two basic distance-relaying schemes used for detecting loss-of-field condition. The settings are calculated here for both of the schemes. There are two hazards to be concerned with in operating a generator underexcited. The first concern is the generator capability curve (GCC) limit. Operation of the generator below the underexcited operating limit of the GCC can result in damage to the unit. The primary protection for this is the under excitation limiter (UEL) control on the excitation system. The other concern is the steady-state stability limit (SSSL). If the unit is operated with too little excitation, it can go out of step.

Figure A.3 shows the GCC, SSSL, and the UEL.

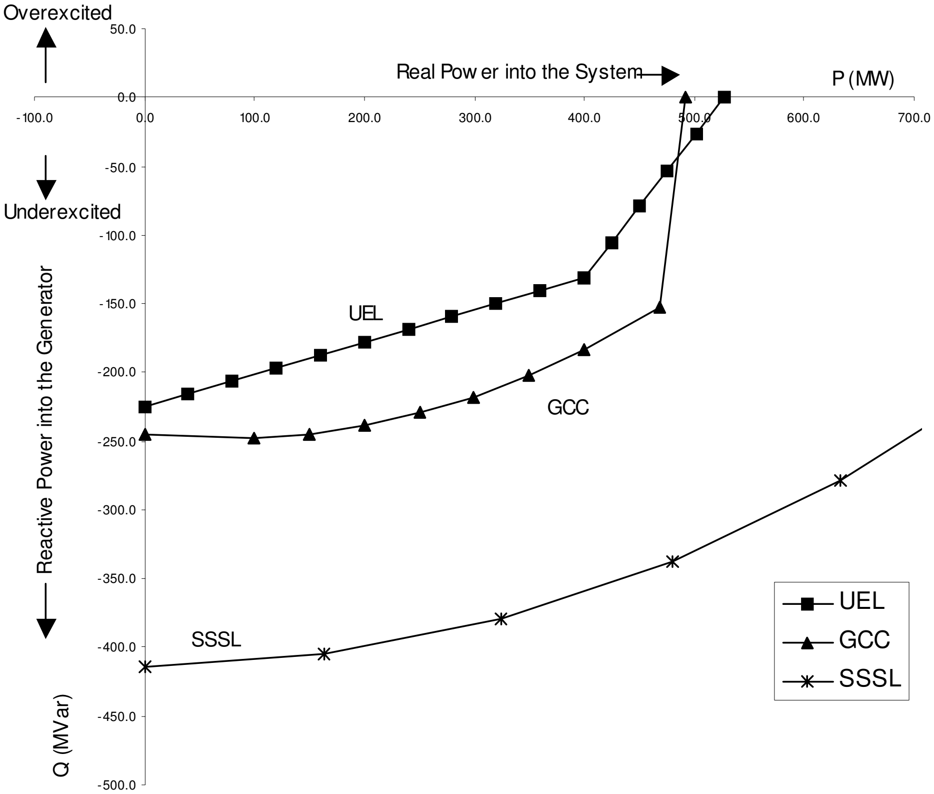

Figure A.3—Generator capability curve

The SSSL can be plotted on the PQ diagram using Equation (A.5) and Equation (A.6). The units should be in primary ohms. The system impedance (X_S) is the transformer impedance (X_T) plus the equivalent system impedance for a weak system condition as that is the worst case for stability.

$$\text{Center offset} = -\frac{1}{2}\mathrm{kV}_{LL}^2\left(\frac{1}{X_d} - \frac{1}{X_s}\right) \tag{A.5}$$

$$\text{Radius} = \frac{1}{2}\mathrm{kV}_{LL}^2\left(\frac{1}{X_d} + \frac{1}{X_s}\right) \tag{A.6}$$

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[10] See IEEE Std C37.2™-1991 [B61]

A.2.1.1 Method #1, negative offset mho

In this example, two mho relay characteristics are used. Since the relay settings are based on CT and VT secondary quantities, the impedances need to be calculated on the CT and VT secondary basis (or relay base quantities).

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 –1.81 Ω

Time delay: A short time delay of approximately 0.1 s 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 –1.81 Ω

Time delay: A minimum time delay of 0.5 s is typically used to prevent relay misoperation during power swing conditions.

In cases where only one mho element is used, the methodology for Zone 2 above is typically employed.

Figure A.4 shows the loss-of-field relay characteristics along with GCC, the UEL, and the SSSL on the RX plane.

The GCC and UEL curves are converted from PQ plane to RX plane using Equation (A.7):

$$Z = \frac{\mathrm{kV}^2}{\mathrm{MVA}} \frac{CT_{ratio}}{VT_{ratio}} \tag{A.7}$$

where

Z is the impedance (at any given angle) in terms of VT/CT secondary
MVA is the MVA of appropriate curve at the selected power factor angle
kV is the voltage rating of the machine in kV times 0.95

A voltage of 0.95 pu is used since that is the lowest voltage that the generator can operate on a continuous basis. During a loss-of-field condition, the voltage may be depressed. The lower generator voltage will move the GCC curve closer to the relay characteristic in the RX plane. A higher generator voltage results in greater separation between the relay and the GCC, creating better coordination.

The SSSL can be plotted on the RX diagram using Equation (A.8) and Equation (A.9). The impedance should be in relay secondary ohms.

$$\text{Center offset} = -\frac{1}{2}(X_d - X_s) = -\frac{1}{2}(20.88 - 3.20) = -8.84\ \Omega \tag{A.8}$$

$$\text{Radius} = \frac{1}{2}(X_d + X_s) = \frac{1}{2}(2.88 + 3.20) = 12.04\ \Omega \tag{A.9}$$

where $X_s = X_{TG} + (X_{\min SG1})$ in relay secondary ohms.

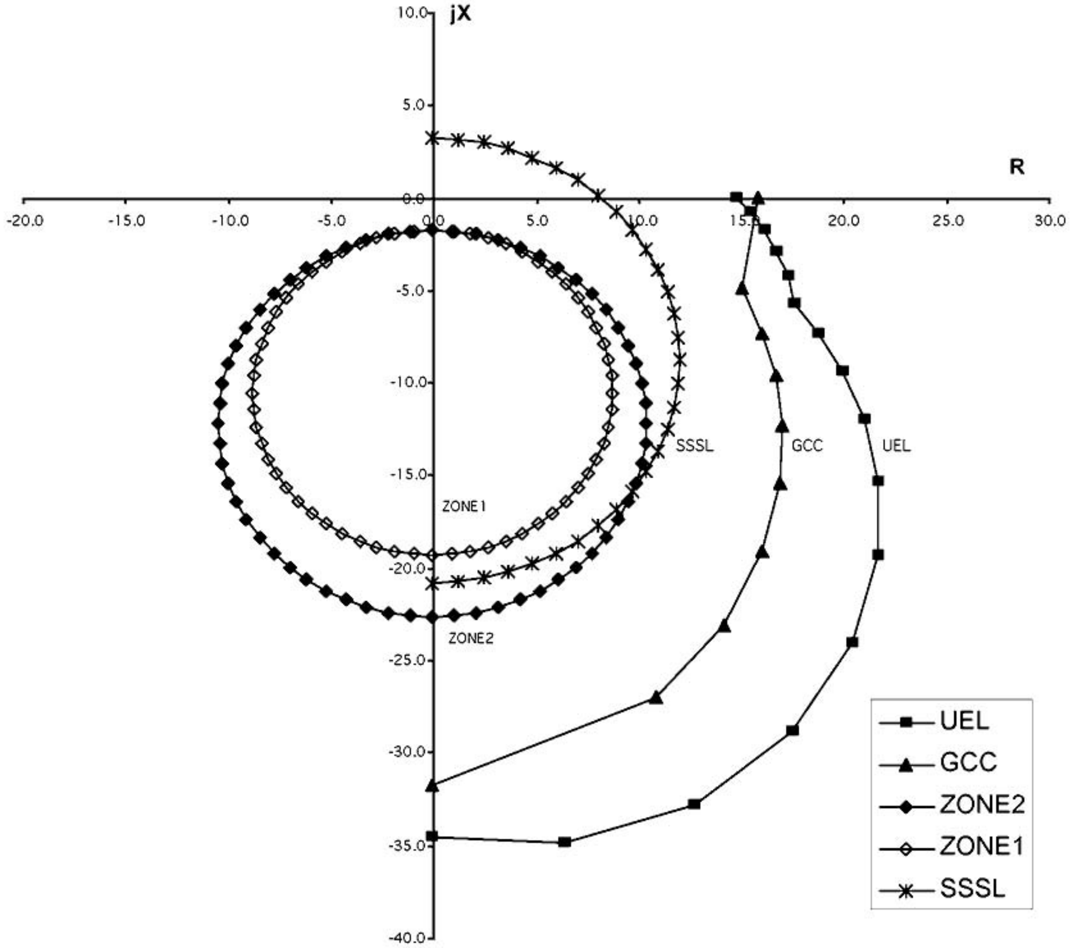

Figure A.4—Loss of field, method #1, RX plane

Figure A.5 shows the loss-of-field elements plotted on the PQ plane. The relay characteristics can be plotted on the PQ plane using Equation (A.10):

$$\mathrm{MVA} = \frac{\mathrm{kV}^2}{Z}\,\frac{CT_{ratio}}{VT_{ratio}} \tag{A.10}$$

where

MVA is the MVA point on the PQ plane of the zone element
kV is the voltage rating of the machine in kV
Z is the impedance point of each zone element characteristic (at any given angle) converted to primary units

A.2.1.2 Method #2, positive offset mho

This method coordinates with the steady-state stability limit. The positive offset also makes the characteristic closely follow the underexcited operating limit of the GCC providing backup protection to prevent damage to the unit. The setting for Zone 2 diameter and offset are designed to trip the machine if it is operated close to the steady-state stability limit. If possible, it is desirable to fit the characteristic between

GCC and SSSL. If that is not possible, it will be necessary to set it such that it limits the machine in the underexcited operating region. Zone 1 trips direct with a short time delay. Zone 2 alarms upon pickup and trips after a long time delay if voltage levels are normal. If voltage levels are low, the Zone 2 timer is bypassed and tripping is accelerated.

Zone 2

Diameter is typically set to 1.1 times X_d plus the weak system source impedance as seen from the terminals of the unit. The 110% multiplier on X_d provides a margin to pick up 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 underexcited operation of the unit, the margin can be set to 125%, which moves the characteristic to approximately halfway between the SSSL and the GCC curves [see Equation (A.11)].

$$\text{Diameter of the circle in pu} = 1.25 + X_d + X_{TG} + X_{\min SG1} \tag{A.11}$$

$$= 1.25 \times 1.1888 + 0.1161 + 0.0662$$

$$= 1.6683 \text{ pu or } 29.3\ \Omega$$

Zone 2 offset: Set the Zone 2 offset to the system source impedance (reactance) as seen from the terminals of the unit [see Equation (A.12)].

$$\text{Offset} = X_{TG} + X_{\min SG1} \tag{A.12}$$

$$= 0.1161 + 0.0662 = 0.1823 \text{ pu or } 3.2\ \Omega$$

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.

Angle of directional element = –13°

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 s to 1 min are appropriate. Since two zones are used along with accelerated tripping on undervoltage, the delay will be set at 1 min.

A transient stability study may be used to refine the voltage supervision and time-delay settings.

Positive sequence or phase undervoltage element. An underexcitation 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 dropout of the undervoltage unit is typically set at 0.8 pu, which will cause accelerated Zone 2 tripping with a time delay of only 1.0 s.

Undervoltage relay setting = 0.8 × 69.28 = 55.42 V, time delay = 1.0 s

Zone 1

Zone 1 diameter: Set to same negative reach as Zone 2 minus the negative offset.

Diameter of the circle in pu:

$$= 1.25\ \text{Xd} - X'_d/2$$

$$= 1.25 \times 1.1888 - 0.20577/2 = 1.3831 \text{ pu or } 24.3\ \Omega$$

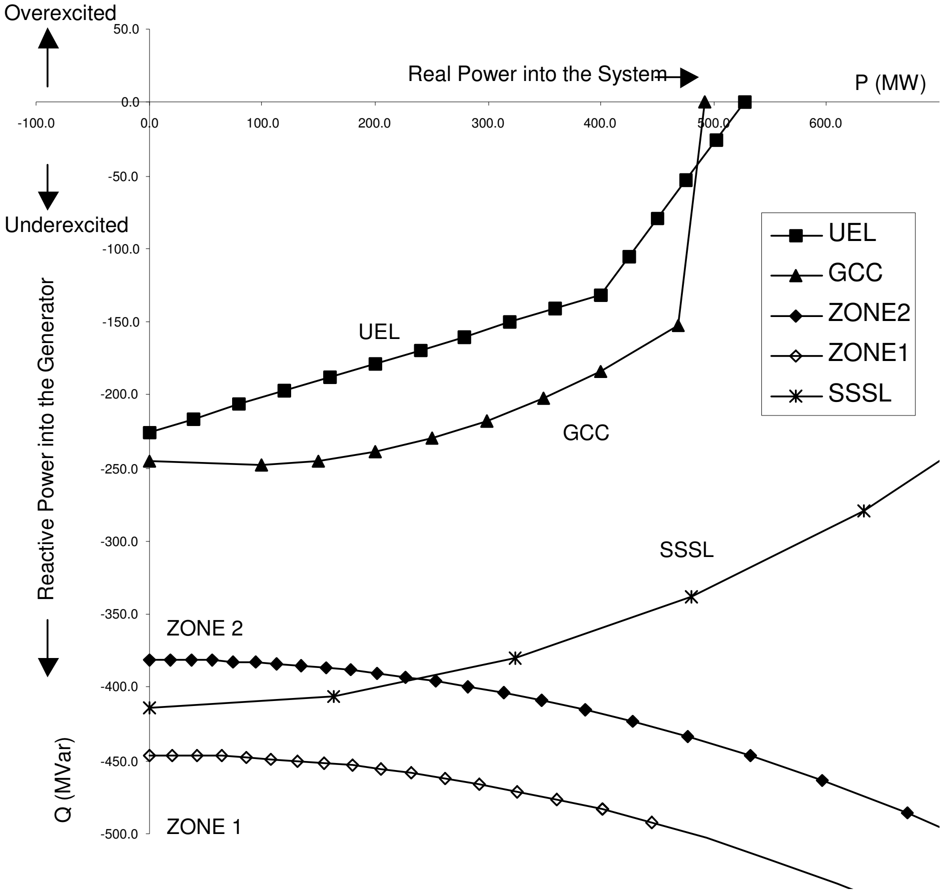

Figure A.5—Loss of field, method #2, RX plane

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

$$\text{Offset} = -X'_d/2 = 0.20577/2 \text{ or } -1.81\ \Omega$$

Zone 1 time delay = 0.25 s

Figure A.6 shows the GCC, UEL, SSSL, and 40 element settings for method 2 plotted on the RX plane. Figure A.7 shows the same characteristics plotted on the PQ plane. It is evident from examining Figure A.5 versus Figure A.7 that, with a positive offset, the Zone 2 element provides better protection for underexcitation conditions in addition to complete loss-of-field conditions.

A.2.2 Loss of synchronism (78)

There are a number of methods for protection against loss of synchronism including single-blinder, double-blinder, and double-lens schemes. All operate on the same basic principle.

Transient stability studies should be performed to determine the appropriate relay settings. If stability studies are not available, the relay may be set using a graphical procedure and conservative settings. A single-blinder scheme (see Figure A.8) is used here to illustrate the graphical method.

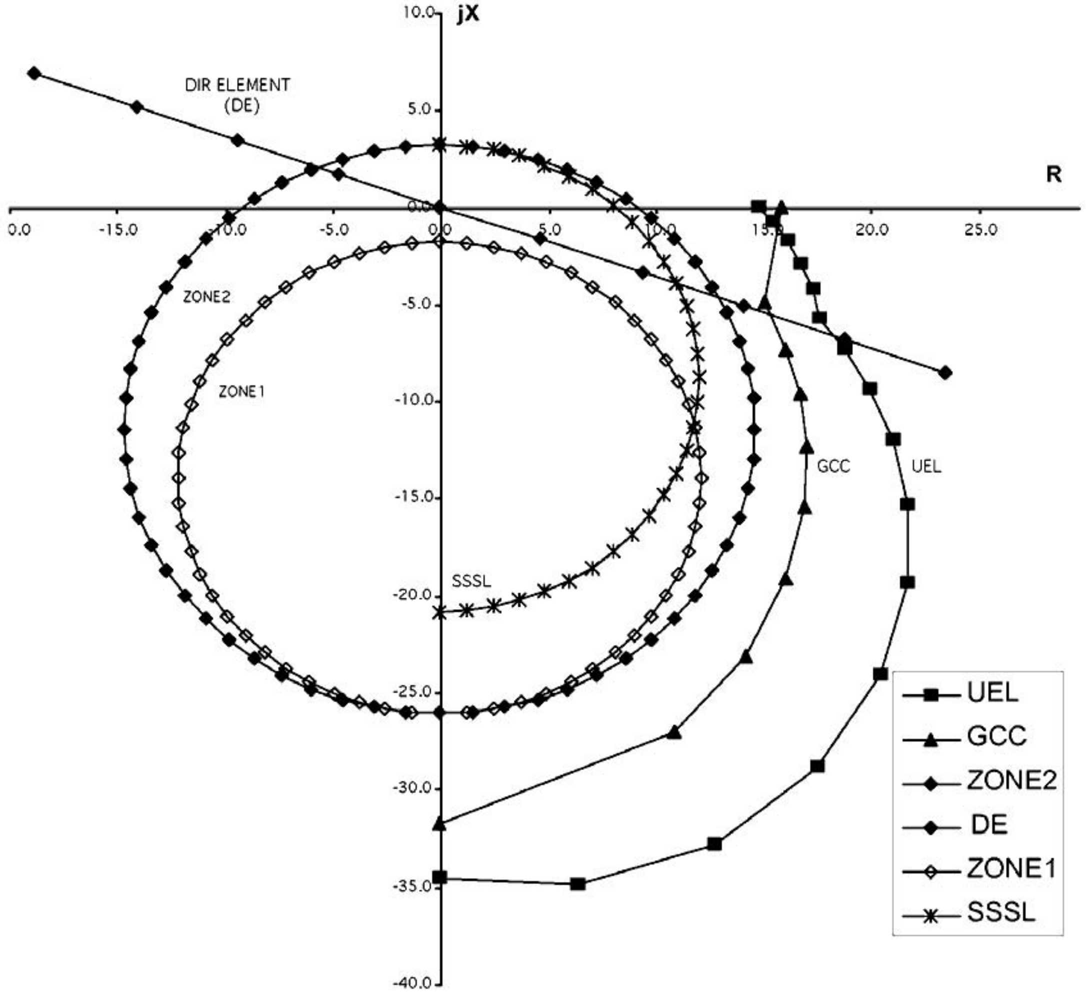

Figure A.6—Loss of field, method #2, RX plane

To simplify setting calculations, resistive components of impedances are neglected and only the reactive components are considered.

Referring to Figure A.8 and converting impedances to relay quantities gives [see Equation (A.13)]:

$$X'_d = 0.20577 \times 17.56 = 3.613\ \Omega,\ X_{TG} = 0.11607 \times 17.56 = 2.04\ \Omega$$

$$X_{\max SG1} = 0.04035 \times 17.56 = 0.7086\ \Omega,\ \beta = 90°$$

$$\text{The blinder distance (d)} = ((X'_d + X_{TG} + X_{\max SG1})/2) \times \tan(90 - (\delta/2)) \qquad \text{(A.13)}$$

Where δ is the angular separation between the generator and the system at which the relay determines instability. If a stability study is not available, this angle is typically set at 120°.

For $\delta = 120°$

$d = 1.64\ \Omega$

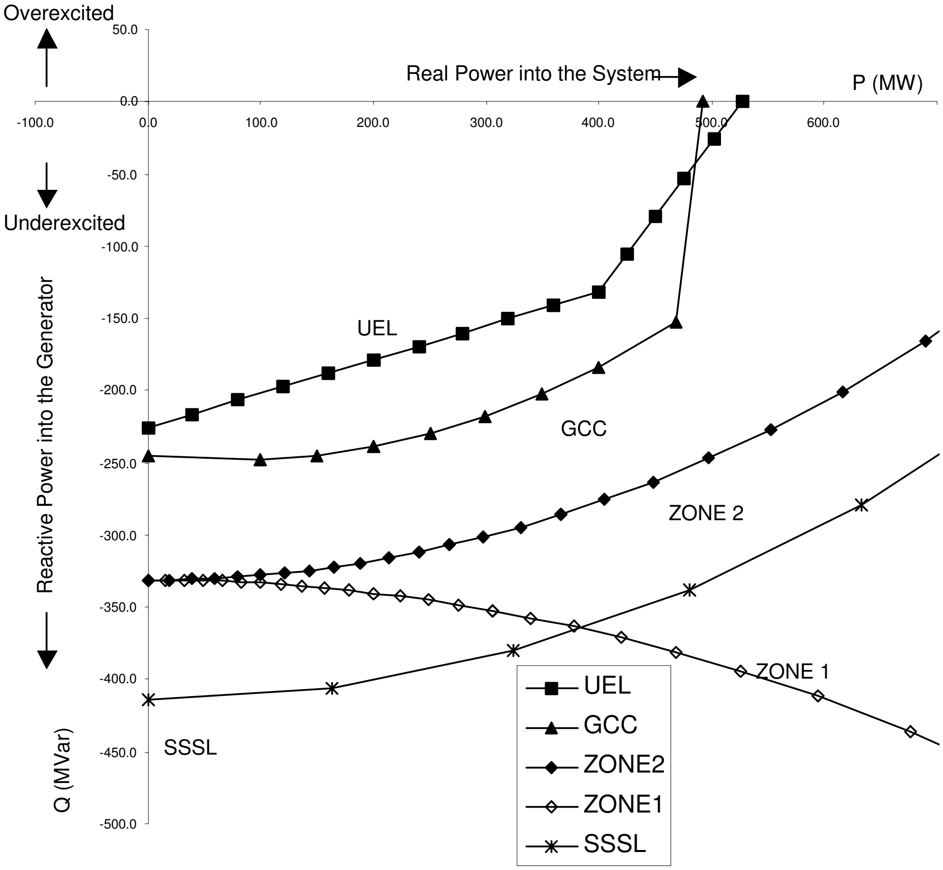

Figure A.7—Loss of field, method #2, PQ plane

Figure A.8 assumes that the relay is connected at the generator terminals.

The mho unit is typically set to limit the reach in the system direction to 1.5 times the GSU impedance. In the generator direction the reach is typically set at twice generator transient reactance.

The diameter of the mho unit is $(2 \times X_d' + 1.5 \times X_{TG}) = 10.29\ \Omega$. Impedance angle of the mho unit is 90°.

The relay should be set to detect the fastest possible swing. In the absence of a stability study, a timer setting of 40 ms to 100 ms for minimum time between the mho and blinder characteristic is appropriate.

A.2.3 Phase distance (21)

The primary purpose of the phase distance (21) relay is to protect the generator from supplying prolonged fault current to a 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 needs to be coordinated with the transmission system primary and backup protection to allow selectivity.

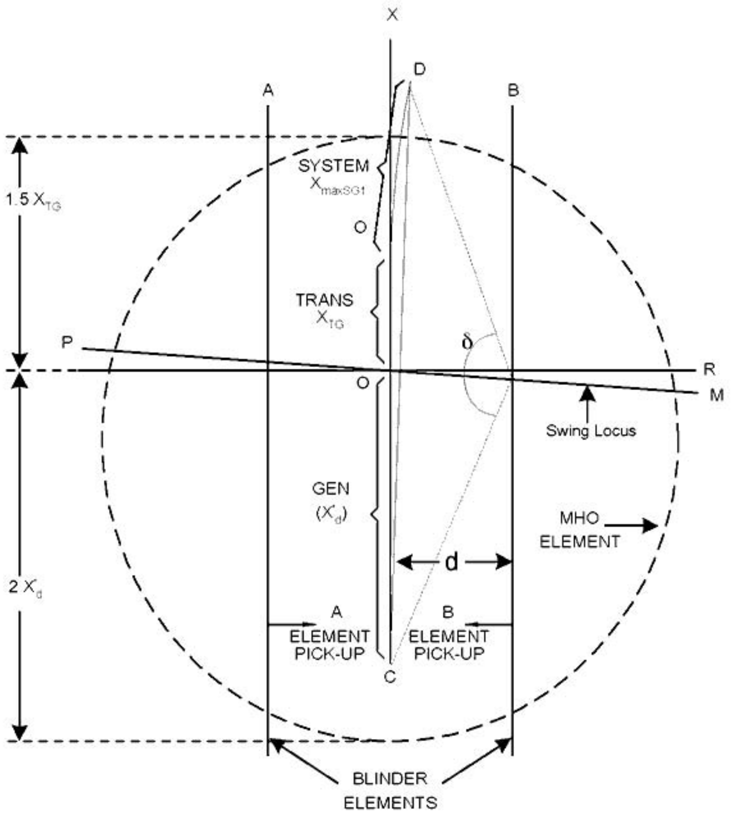

Figure A.8—Loss of synchronization characteristics

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:

a) *In-feed:* Apparent impedance due to in-feed may require larger reaches, however, settings to cover long lines may overreach adjacent short lines.

b) *Load impedance:* Settings should be checked to ensure the maximum load impedance [$Z_{\max\ load} = \mathrm{kV}_G^2/\mathrm{MVA}_G$ at rated power factor angle (RPFA)] does not encroach into the reach. An MVA_G value of 150% to 200% at rated power factor is recommended to avoid tripping during normal load.

One zone of distance relay with a mho characteristic is commonly used for phase fault backup. In some cases two zones with mho characteristics are applied. Typical settings for a two-zone phase distance protection are given here. If only one zone is used settings will be based on its application's requirements for remote backup similar to Zone 2.

Zone 1

Set Zone 1 to the smaller of the two following criteria:

1) 120% of unit transformer

$$1.2 \times X_{TG} \times Z_{B\_relay} = 2.45\ \Omega$$

2) 80% of Zone 1 reach setting of the line relay on the shortest line (neglecting in-feed)

Then the Zone 1 reach setting of the phase distance relay is equal to transformer impedance plus 80% of the Zone 1 line relay setting.

Assuming the line relay reach on the shortest line is set at 80% of the line:

$$(X_{TG} + 0.8 \times (0.8 \times Z_{SLG1})) \times Z_{B\_relay} = 4.6\ \Omega$$

Z_1 reach is set to 2.45 Ω, maximum torque (sensitivity) angle (MTA_1) = 90°.

Time delay of 0.5 s gives the primary protection (generator differential, transformer differential, and overall differential) enough time to operate before the operation of phase distance function. If breaker failure protection is installed, the time delay should be set to coordinate with this scheme.

Zone 2

Set Zone 2 to the smaller of the three following criteria:

A) 120% of longest line (with in-feed). If the unit is connected to a breaker and a half bus, this would be the length of the adjacent line.

B) 50% to 66.7% of load impedance (200% to 150% of the GCC) at the RPFA

C) 80% to 90% of load impedance (125% to 111% of the GCC) at the maximum torque angle

The apparent impedance reach to the end of the line will require an in-feed calculation because both the generator and the utility will contribute fault current as shown in Figure A.9. The transient reactance is used in this calculation since this is for a time delayed backup element [see Equation (A.14) and Equation (A.15)].

$$Z_{Total} = \frac{1}{\dfrac{1}{Z_{\max SG1}} + \dfrac{1}{X'_d + X_{TG}}} + Z_{LLG1} = 0.04566 + j0.50024 \text{ pu} \tag{A.14}$$

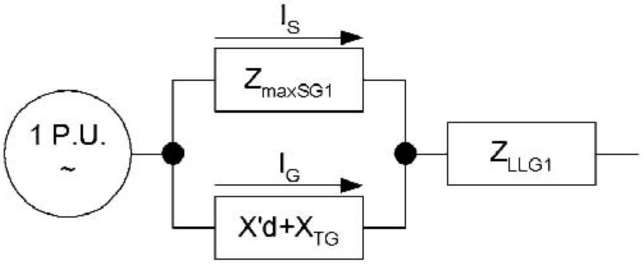

Figure A.9—Equivalent circuit for apparent impedance with in-feed

$$X_{Total} = \frac{1}{Z_{Total}} = 0.18097 - j1.98253 \text{ pu} \tag{A.15}$$

Current divider rule [see Equation (A.16) and Equation (A.17)]:

$$I_S = \left| I_{Total} \times \frac{X'_d + X_{TG}}{X'_d + X_{TG} + Z_{\max SG1}} \right| = 1.76895 \text{ pu} \tag{A.16}$$

$$I_G = \left| I_{Total} \times \frac{Z_{\max SG1}}{X'_d + X_{TG} + Z_{\max SG1}} \right| = 0.22207 \text{ pu} \tag{A.17}$$

The apparent impedance to the end of the longest line is shown in Equation (A.18):

$$Z_{\text{LINE\_Apparent}} = X_{TG} + \left(\frac{I_S + I_G}{I_G}\right) Z_{LL1G} \times Z_{B\_relay} = 75.5\ \Omega\angle 85° \qquad \text{(A.18)}$$

Based on criteria A previously defined, the Z_2 reach is:

$Z_{2\_\text{Line}} = 1.2 \times 75.5\ \Omega < 85° = 90.6\ \Omega < 85°$

Based on the criteria B previously defined, the Z_2 setting is:

The reach of the 21 element should not exceed 50% to 66.7% (200% to 150% of the GCC) load impedance at rated power factor. Otherwise the distance element could trip on load or power swings. This can be calculated as shown in Equation (A.19) and Equation (A.20):

$$Z_{\text{max}\ load} = \frac{\text{kV}_G^2}{\text{MVA}_G} \frac{CT_{Ratio}}{VT_{Ratio}} = 17.56\ \Omega\angle 39.64°(0.77\text{pf}) \qquad \text{(A.19)}$$

Z_2 reach setting at MTA_2 based on $Z_{\text{max}\ loading}$

$$Z_2(\text{at MTA}_2) = 0.67 \times \frac{Z_{\text{max}\_load}}{COS(MTA_2 - RPFA)} = 16.6\ \Omega\angle 85° \qquad \text{(A.20)}$$

Based on the criteria C previously defined, the Z_2 setting is:

The reach of the 21 element should not exceed 80% to 90% (125% to 111% of the GCC) load impedance at rated power factor. Otherwise the distance element could limit the GCC. This can be calculated as shown in Equation (A.21) and Equation (A.22):

$$Z_{GCC\_\text{MTA}} = \frac{\text{kV}_G^2}{\text{MVA}_{GCC\_\text{MTA}}} \frac{CT_{Ratio}}{VT_{Ratio}} = 23.14\ \Omega\angle 85° \qquad \text{(A.21)}$$

$$Z_{2\_MTA2} = 0.9 \times Z_{GCC\_MTA} = 20.8\ \Omega<85° \qquad \text{(A.22)}$$

Since the criteria B gives the smallest reach setting, the Z_2 reach is set at 16.6 Ω with an MTA setting of 85°.

The maximum, secure reach setting for the Zone 2 element is 16.6 Ω. This is much less than the 90.2 Ω reach required to see past the remote bus. In this situation, it is important to review the protection systems on adjacent zones to ensure that they have adequate redundancy to cover both relay failure and breaker failure contingencies.

Figure A.10 shows the distance element characteristics and the GCC plotted on the RX plane. The GCC is plotted using the same formula given in A.2.1 [see Equation (A.23)].

$$Z = \frac{\text{kV}^2}{\text{MVA}} \frac{CT_{ratio}}{VT_{ratio}} \qquad \text{(A.23)}$$

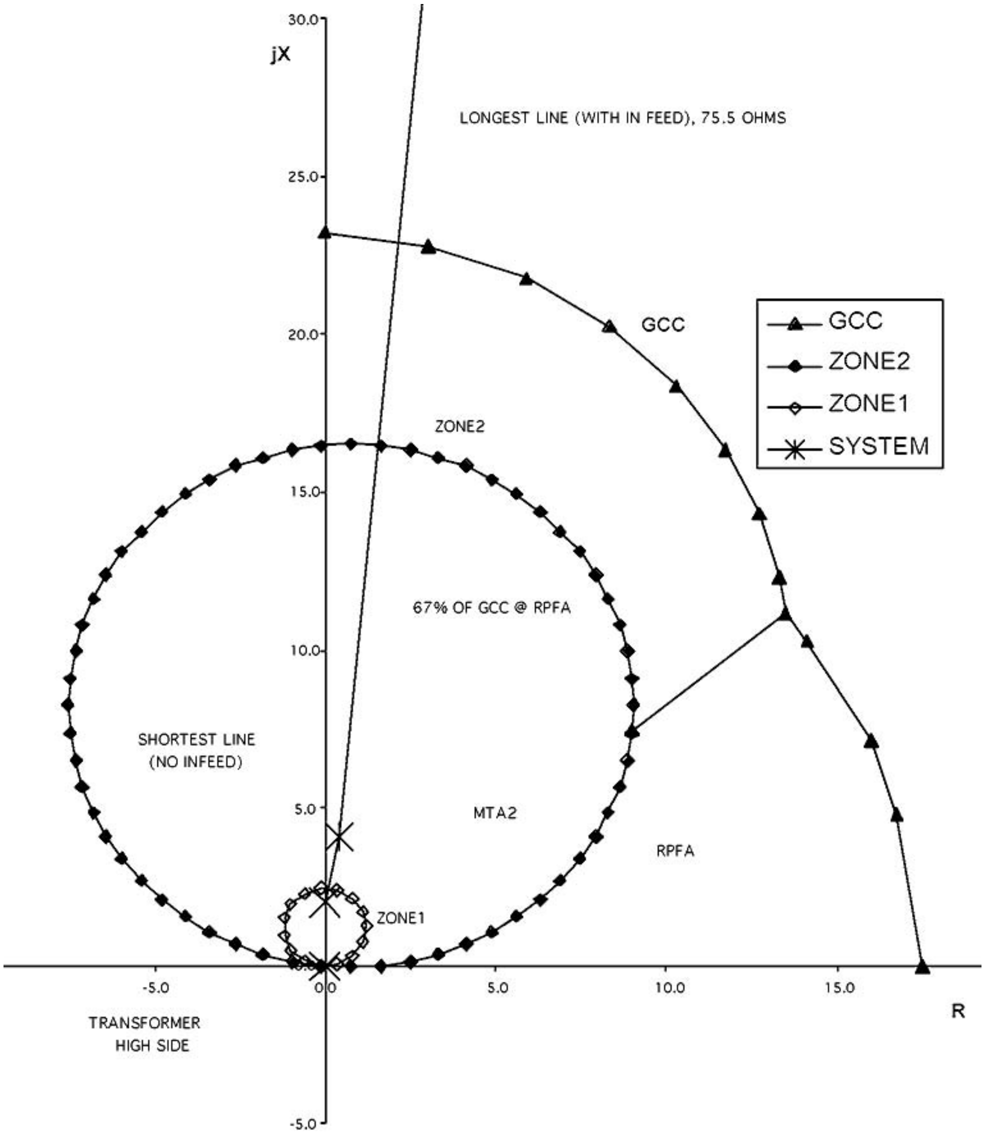

Figure A.10—Distance element, RX plane

There are two criteria for setting the time delay of this long overreaching element: it should coordinate with other time delayed elements on the transmission system; it should be set longer than the time of the apparent impedance encroachment on the element during a stable power swing.

This second criteria becomes more dominant the lower the margin is between element reach and generator maximum loading. A typical time delay setting for this element would be similar to the Zone 3 remote backup element time delay used for transmission relays. In this example, we will use a 1 s setting.

A.2.4 Inadvertent energizing

There are several schemes to provide protection for inadvertent energizing. For the purpose of calculating typical relay settings, a voltage supervised overcurrent scheme is used and typical settings are calculated.

Figure A.11 shows the equivalent circuit of the generator, transformer, and the system during inadvertent energizing condition. Assuming a system equivalent voltage of $E_S = 1.0$ pu, the worst-case current (relay secondary quantities) during inadvertent energizing is given by Equation (A.24):

$$I = \frac{ES}{X_2 + X_{TG} + X_{\min SG1}} = \frac{69.28}{(0.17676 + 0.11607 + 0.0662) \times 7.56} = 10.99 \text{ A} \tag{A.24}$$

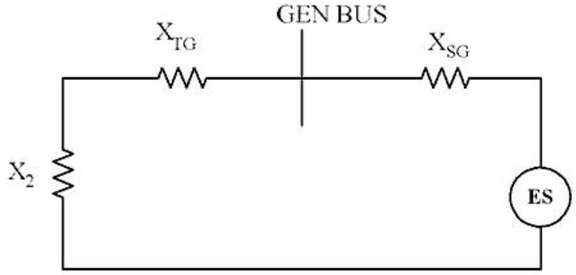

Figure A.11—Equivalent circuit of generator, transformer, and the system

Overcurrent (50) function

Pickup of overcurrent is typically set at ≤ 50% of the worst-case current value. Thus, a set point of 50% would be 5.44 A for a three-phase inadvertent event.

Currents should also be calculated for one or two pole breaker-head flashover inadvertent energization since they both will draw lower currents than the three-phase energization event. In no case should the overcurrent function's pickup setting be less than 125% of the generator's rated current.

Undervoltage (27) function

Set the undervoltage function at 50% of the rated voltage (assuming phase-to-ground neutral VT input).

$$= 0.5 \times 69.28 = 34.64 \text{ V}$$

Pickup time delay for the 27 function should be set longer than the system fault clearing time. The accidental energization scheme is armed for instantaneous operation after the voltage has dropped below its pickup for a certain period of time implying the unit is off-line. Typically this delay time to arm is set at 1.5 s, which is longer than the system's fault clearing time.

The accidental energization scheme is disarmed after the voltage rises above the 27 function's pickup for a short period of time. Typically this time is set at 15 cycles.

A.2.5 Phase differential (87)

The variable slope percentage differential relay is the most widely used form of differential protection for generators. The pickup and slope of the differential relay should be set to as sensitive as possible to detect internal winding faults while not misoperating for external faults. A typical setting of 0.3 A and 10% slope provides sensitive protection and prevents misoperation during external faults due to CT ratio errors. The slope setting may need to be higher (for example 20%) if the relay does not automatically increase the slope at higher currents to prevent misoperation due to CT saturation. Differential relays are usually set with no intentional time delay. However, if CT saturation is possible during external faults time delay may be required to prevent misoperation during transients.

Pickup: 0.3 A (≈ 8% or 0.08 pu)

Slope: 10%

Time delay: No intentional time delay

It is important to verify the ac performance of the CT for worst-case faults. Considering a three-phase fault on the terminals of the generator, the following equivalent circuit (see Figure A.12) may be used to calculate the fault current.

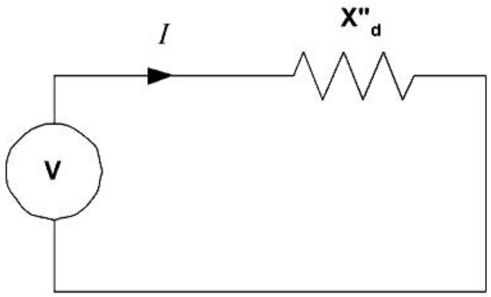

Figure A.12—Equivalent circuit for a three-phase fault at the generator terminals

$X_d^{''}$ = 0.17847 pu

= 0.1784 x 17.56 = 3.13 Ω

V = 69.28 V

The worst-case fault current (*I*) = 69.28/3.134 = 22.11 A

For the overall differential function the worst-case fault current during an external fault at the unit transformer terminals is given by the following equivalent circuit (see Figure A.13).

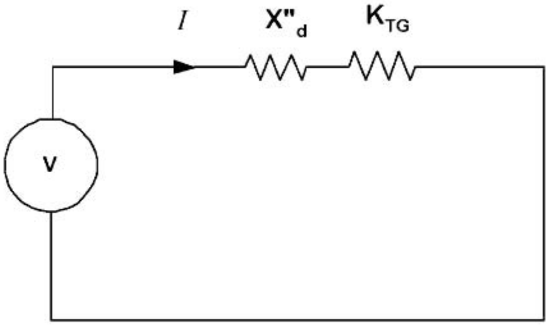

Figure A.13—Equivalent circuit for three-phase fault at the unit transformer terminals

X_{TG} = 0.116071 pu

= 0.11607 x 17.56 = 2.04 Ω

V = 69.28 V

The worst-case fault current (I) = $\mathrm{V}/X_{TG} = X''_d$) = 69.28/(2.038 + 3.134) (A.25)

I = 13.4 A

Now the CT secondary voltage may be calculated using the following equivalent circuit (see Figure A.14).

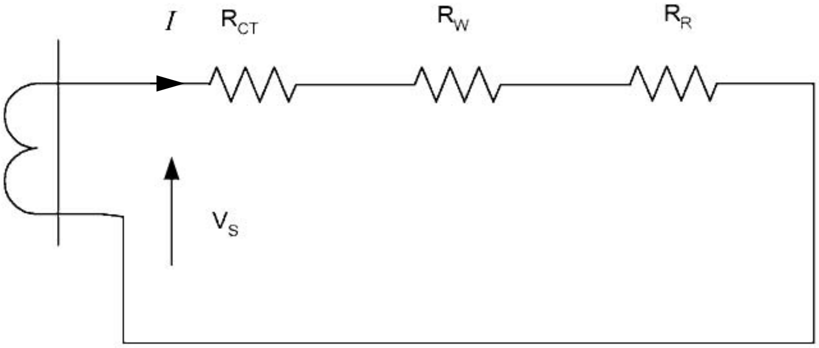

Figure A.14—Equivalent circuit of the CT secondary wiring

where

R_{CT} = CT burden
R_W = total resistance of the CT secondary wiring
R_R = relay burden
$V_S = I(R_{CT} + R_W + R_R)$

Where I is the fault current and V_S is the CT secondary voltage. In order to make sure that the CT is in the linear range (to avoid ac saturation of the CTs), V_S should be less than the knee-point voltage of the CT excitation characteristics. See Std C37.110.

A.2.6 Voltage controlled/restrained overcurrent (51V)

This function provides backup protection for system faults. The steady-state fault current for a three-phase system fault may result in generator current magnitudes less than the full-load current of the generator. However, the fault will cause generator terminal voltage to drop significantly. In order for a current relay to detect and properly operate for uncleared system faults, either a voltage controlled or voltage restrained overcurrent relay should be used.

For a three-phase fault at the output terminals of the transformer, the steady-state fault current (CT secondary) may be calculated by the following equivalent circuit (see Figure A.15). In order to find the lowest fault current, it is assumed that the automatic voltage regulator is off-line and the generator was not loaded prior to fault. This is the limiting case as it assumes the transient and subtransient times have elapsed and machine impedance has switched to its synchronous value (steady-state fault current).

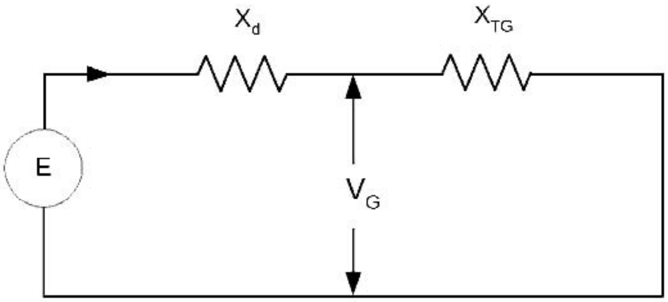

Figure A.15—Steady-state equivalent circuit for three-phase fault at the transformer terminals

Where E is the no load voltage at the generator terminals and the fault current (I) is given by Equation (A.26):

$$E/(X_d + X_{TG}) = 69.28/((1.1888 + 0.11607) \times 17.56) = 3.02 \text{ A} \tag{A.26}$$

It may be seen that the steady-state fault current is less than the full-load current.

However, the voltage at the generator terminals during the fault is given by:

$$V_G = 3.02 \times 0.11607 \times 17.56 = 6.16 \text{ V}$$

Note this is less than 10% of rated generator terminal voltage. This voltage will be higher if the generator was loaded prior to the fault and/or if the voltage regulator is in service. However, even with the regulator in service, the generator current and voltage will be limited by the excitation system ceiling voltage. This is typically between 1.5 times to 2 times the rated exciter voltage. Thus, generator voltage will still be greatly reduced below normal for a fault at the output terminals of the transformer.

Considering the application of a voltage controlled overcurrent relay, the following are typical pickup settings:

Overcurrent pickup: Set at 50% of generator full-load current = (3.95/2) = 1.98 A

Undervoltage element pickup: Set at 75% of rated voltage = 69.28 × 0.75 = 52 V

Considering the application of voltage restrained overcurrent relay the following are typical pickup settings:

Overcurrent pickup at rated voltage: 150% of full-load current = 3.95 × 1.5 = 5.93 A

During the fault condition when the voltage drops, the overcurrent relay pickup also drops linearly, and it should be verified that for the limiting case the relay pickup should be around 50% of the fault current to ensure definite relay operation.

In this example, for the limiting case the generator current is 3.02 A (CT secondary) at 6.16 V (VT secondary), therefore, the relay pickup current at 6.16 V should be about 1.5 A. (This is approximately 25% of the 51V pickup setting at rated voltage or 25% of 5.93 A).

If this relay is also used to provide thermal protection (as is sometimes the case with diesel generators) the 51V inverse curve should be shown to be below the generator thermal damage curve.

The inverse time curve and time dial settings for both voltage control and voltage restraint relays should be set to coordinate with system line relays for close-in faults on the transmission lines at the plant. A time-current plot of the 51V relay function along with the transmission line relays; time-current function will illustrate the coordination between these relays.

A.2.7 100% stator ground fault protection

The stator ground fault protection for a high-impedance grounded generator is typically provided with neutral overvoltage (59G), which covers about 95% of the winding measured from the output terminals.

In order to provide 100% coverage for ground faults, additional protection schemes are applied. The example uses a third harmonic undervoltage scheme connected at the secondary of the grounding transformer for setting calculations. Field measurements of third harmonic voltages during various loading conditions are required in order to set this function. Table A.1 gives the measured third harmonic voltages (based on primary of the grounding transformer) for the example generator:

From Table A.1 the terminal end and neutral end third harmonic voltages are plotted and shown in Figure A.16.

Table A.1—Measured primary third harmonic neutral voltages

		Measured primary third harmonic voltages				
MW	**Mvar**	**X-phase**	**Y-phase**	**Z-phase**	**Average phase volts**	**Neutral voltage**
0	0	66.0	69.7	64.2	66.6	–18.9
80	30	80.7	84.3	88.0	84.3	–52.4
98	23	89.8	93.5	97.2	93.5	–56.8
126	19	104.5	119.2	117.3	113.7	–81.1
147	15	128.3	130.2	122.8	127.1	–94.0
174	20	135.7	143.0	141.2	139.9	–108.2
201	19	165.0	161.3	155.8	160.7	–117.9
227	15	179.7	179.7	181.5	180.3	–146.4
384	30	242.0	238.3	236.5	239.0	–191.3
408	25	242.0	249.3	240.2	243.8	–198.9
447	27	265.8	247.5	251.2	254.8	–207.5
482	20	276.8	276.8	258.5	270.7	–217.0

Note that in Table A.1 the terminal end voltage is shown as positive voltage, whereas the neutral end voltage is shown as negative voltage. The voltage may be considered evenly distributed along the length of the generator winding. Normally, the third harmonic voltage will vary with MW and Mvars.

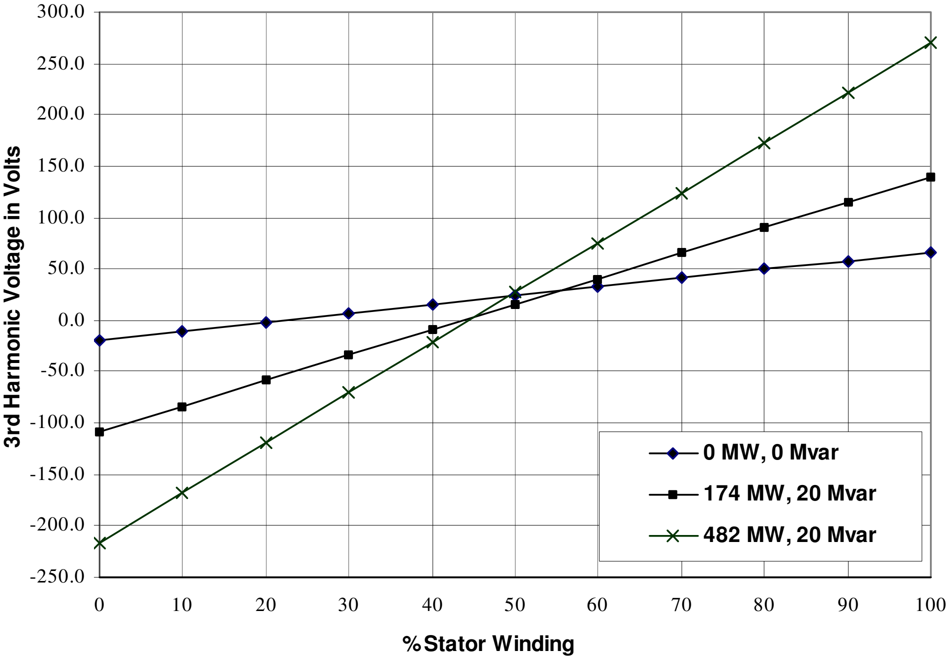

Figure A.16—Third harmonic voltage distribution for various loads

A line may be drawn to represent the distributed third harmonic voltage in the generator at a specific MW and Mvar load. The end points of the graph are the test data points for the respective MW and Mvar loads. Note that because the measured third harmonic voltage is different for each generator load, the slope of each respective line is different. Because the line slopes are different, the point that the line crosses the X-axis changes for different load conditions. A similar effect would be seen if the field excitation is varied at a fixed load.

The third harmonic relay scheme measures the magnitude of the generator neutral third harmonic voltage, and operates when that voltage magnitude is reduced below the trip point. The relay determines the absence of a third harmonic voltage as an abnormal condition. Therefore, either the relay setting is set below the minimum expected generator neutral third harmonic voltage magnitude or there needs to be some type of supervisory control over the relay operation. Normally the generator terminal voltage is used to supervise the relay output. In some cases generator forward power also supervises the relay tripping. However this will leave the generator unprotected on start-up.

If a stator ground occurs at the point that the line crosses zero, there would be no change in the third harmonic voltage magnitude at either the neutral or terminal ends of the generator. A ground at any other location will cause the line to shift such that the zero crossover point is at the location of the ground. If the fault is near the neutral end of the generator, there will be a reduction in the third harmonic voltage magnitude as measured at the neutral end.

Assuming a 27TH relay pickup of 18 V, the percentage of winding covered for a 174 MW loading is around 7% from the neutral end as shown in Figure A.17.

Assuming the same 18 V relay pickup, and a new load of 482 MW, the fault would have to be closer to the generator neutral (than for the 174 MW condition) in order for the relay to detect the fault. This is due to the higher slope of the 482 MW line. For the 482 MW line, the fault would have to be within 3.7% of the neutral to be detected as shown in Figure A.18.

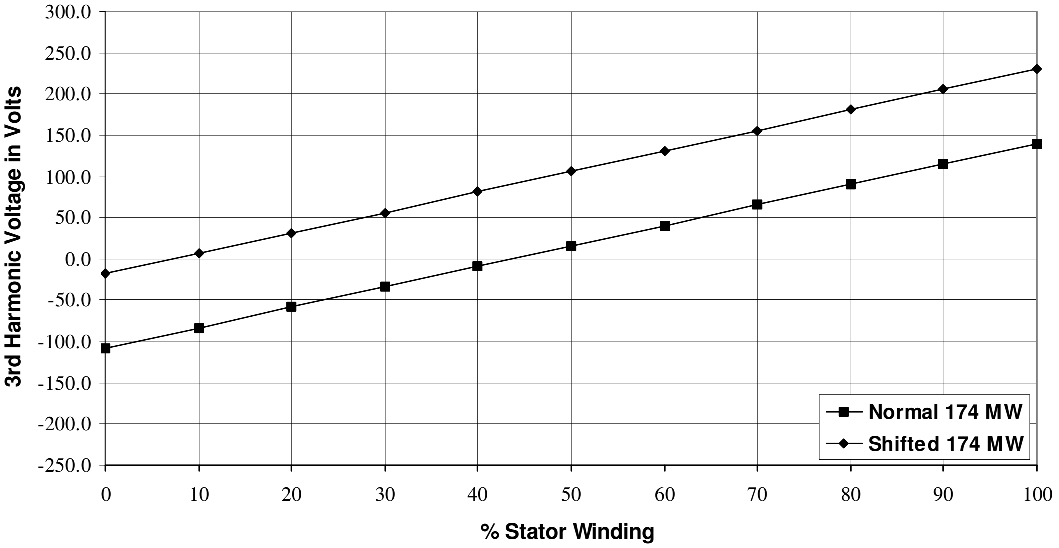

Figure A.17—Third harmonic voltage distribution at 174 MW

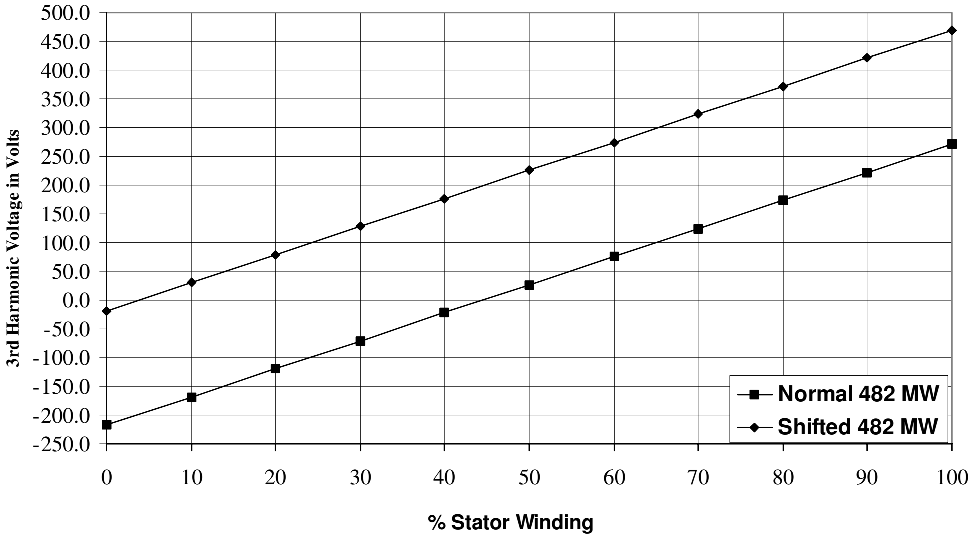

Figure A.18—Third harmonic voltage distribution at 482 MW

To determine the percent coverage of the third harmonic relay, the worst-case operating condition should be determined. The measurements should include no-load to full-load operation and a variation of field current for over- and underexcitation.

To obtain security against relay misoperation while providing continuous coverage, a ratio of the minimum normal generator neutral third harmonic voltage to relay pickup of 2:1 would be preferred. In this example with the no-load generator neutral third harmonic voltage at –18.9 V, the preferred relay setting would be around 9 V to 10 V.

If the relay cannot be set as sensitive as needed, forward power supervision may be used. This will result in not protecting the generator during start-up. As an alternative, an auxiliary VT may be used to increase the third harmonic voltage to the relay. Exercise care to avoid an overvoltage of the relay during ground faults at the generator terminals.

The third harmonic undervoltage relay is used in conjunction with other relays to obtain the total ground fault protection of the generator stator. The other relays cover from the generator terminals to the point of minimum sensitivity as previously determined, with some overlap of the protective zones. A 59G setting of 5 V will be used to demonstrate this principle. A ground fault at the generator's terminal results in the maximum voltage across the grounding transformer's primary. The 59G relay will measure that primary voltage, reflected to the secondary by the transformer ratio. The sensitivity of the relay (percent coverage) is determined by the relay pickup. The maximum secondary voltage the relay will measure in this installation is 192.45 V:

$$\frac{20\ 000\text{V}}{\sqrt{3} \times 60} = 192.45\text{V}$$

The grounding transformer secondary non-fault voltage is normally zero. Since the relay operates when the secondary voltage rises above its pickup (5 V in this case), the relay will operate for all faults except those within 2.6% of the neutral end of the generator.

$$\frac{5\text{V}}{192.45\text{V}} = 0.026 \text{ or } 2.6\%$$

The time setting for the 59G relay is selected to provide coordination with other system protective devices. When grounded-wye/grounded-wye VTs are connected at the machine terminals, the 59G relay should be time coordinated with VT fuses for faults on the transformer secondary windings. The voltage relay may have to be coordinated with system relaying for system ground faults. System phase-to-ground faults will induce zero-sequence voltages at the generator due to capacitive coupling between the windings of the unit transformer. This induced voltage will appear on the secondary of the grounding distribution transformer and may cause operation of the 59G relay. A time delay setting of 5 seconds is suggested for 59G relay.

The relay will cover 100 – 2.6 = 97.4% of the generator. Therefore there is complete coverage, since the 27TH function will cover between 0% to 3.7% and the 59G relay will cover between 2.6% to 100% of the winding. Figure A.19 illustrates the overlapping of the third harmonic relay function (27TH) and the normal stator ground protection (59G). An independent 50/51G relay connected at the generator neutral provides a redundant trip for stator ground faults.

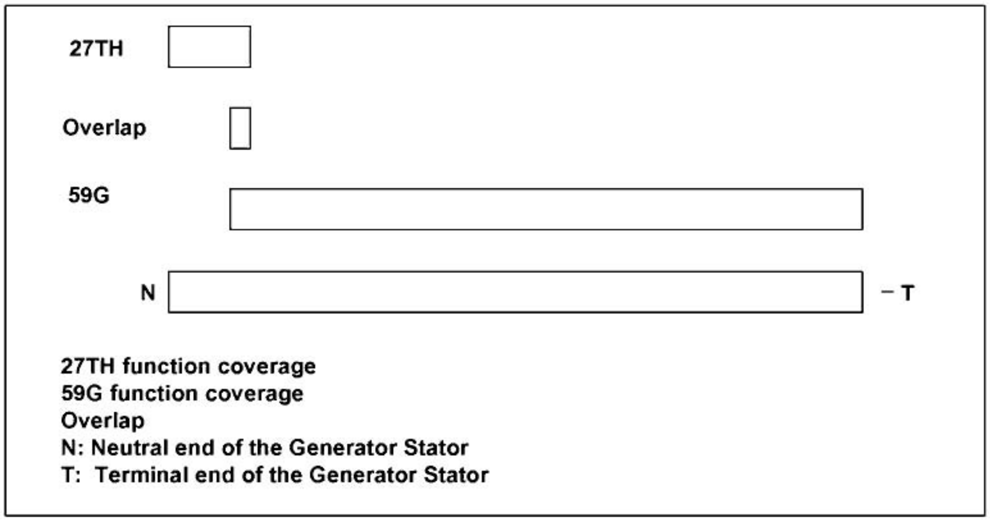

Figure A.19—Coverage of 27TH and 59G functions

Summary of the preceding settings is as follows:

59G element: Pickup = 5 V
Time delay = 5 s
27TH element: Pickup = 0.3 V (18 V primary)
Time delay = 5 s

Since the 18 V pickup is close to the minimum measured third harmonic voltage during no load, 27TH function should be supervised by a forward power element to prevent tripping during start-up or the pickup of the 27TH function could be dropped to 0.15 V (if possible).

A.2.8 Unbalanced currents [negative-sequence overcurrent (46)]

Protection from unbalanced currents is usually provided using a negative-sequence overcurrent relay. The ability of generator to accommodate unbalanced currents is specified by the manufacturer in accordance with IEEE Std C50.12 and IEEE Std C50.13.

Based on direct-cooled cylindrical synchronous generator, the negative sequences withstand capabilities for the sample generator is as follows (see IEEE Std C50.13).

Permissible continuous negative-sequence current (I_2) = 8%

Permissible short time unbalanced current $(T_2^2 t = K) = 10$

Typical relay settings for inverse time protection are as follows:

Pickup setting: 7%
Time dial $((K = I_2^2 t)$: 9
Linear reset time: 4 min

If a definite time element is also available in the relay it may be set below the inverse time pickup setting and with sufficient time delay to prevent nuisance alarms. For this example, a 5% pickup and 30 s time delay are selected to provide an alarm indication.

The inverse time curve selected (value of *K*) should be coordinated with system phase fault protection. The 46 function should not operate faster than the primary system phase fault protection while still protecting the generator.

A.2.9 Reverse power relay (32)

A reverse power relay is used to detect motoring condition of the generator (see Figure A.20). A separate reverse power relay may be used in the sequential trip logic scheme where motoring is allowed for a short time to ensure the prime mover has lost sufficient energy to prevent overspeed following a turbine trip (see Figure A.21). The sensitivity and setting of the relays depend upon the type of prime mover involved. Typically the real power pickup setting would be the same for both relays. The time delays and logic would be different. The prime mover for the sample generator is a steam turbine, and the reverse power during motoring is about 1% of nameplate.

Pickup setting: A typical pickup setting would be 0.5% of nameplate [a margin of 0.5% below the 1% motoring value: 0.005 × 492 MVA × 0.77 pf = 1.89 MW (primary)]

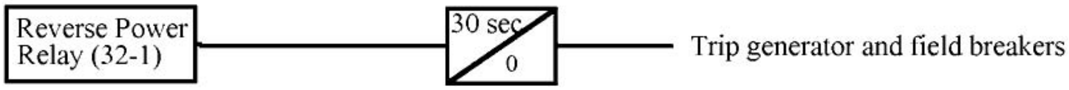

Figure A.20—Reverse power relay logic for anti-motoring

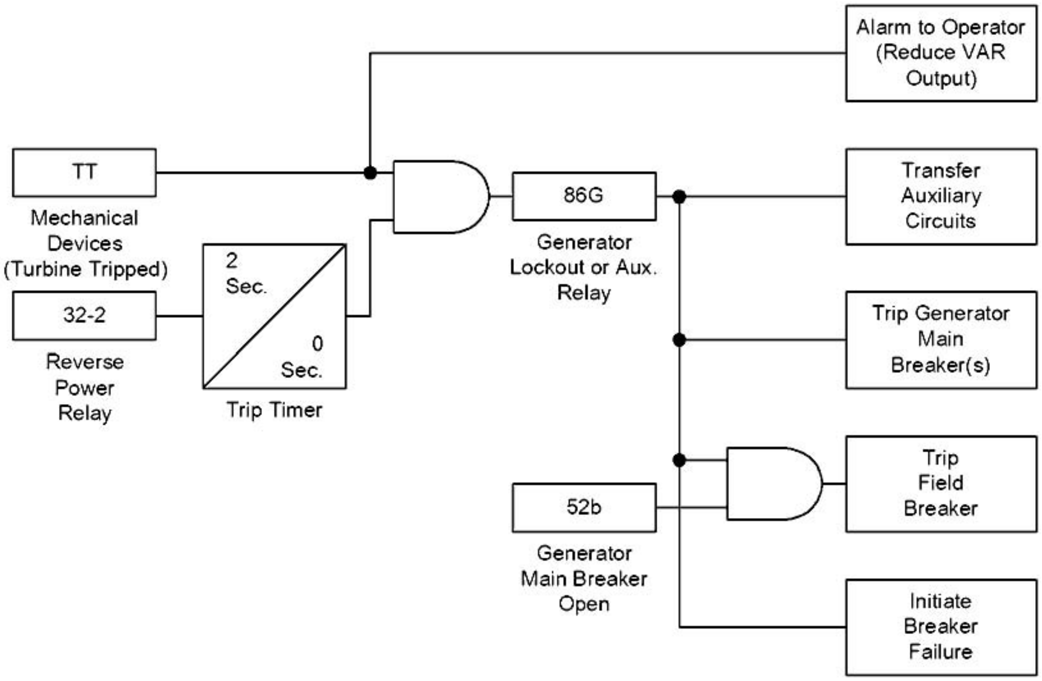

Figure A.21—Reverse power relay logic for sequential trip

Anti-motoring scheme (32-1)

Pickup setting: A typical pickup setting would be 0.5% of nameplate [a margin of 0.5% below the 1% motoring value: 0.005 × 492 MVA × 0.77 pf = 1.89 MW (primary)]

Time-delay setting: Long enough to allow the controls to pick up load after synchronizing online and allow for system swings but less than the maximum allowed motoring time specified by the manufacturer. A typical setting is 30 s.

Sequential trip scheme (32-2)

Pickup setting: 0.5% of nameplate MW [a margin of 0.5 below the 1% motoring value: 0.005 × 492 MVA × 0.77 pf = 1.89 MW (primary)]

Time-delay setting: 2 s (enough time to assure motoring)

It has been demonstrated that some reverse power relays are desensitized under high var (low power factor) conditions. Deviations of only ±1° from an ideal reverse power characteristic have been correlated to changes of 260% to 62% in relay pickup. To avoid misoperation of sequential tripping due to failure of the 32 function, high var loading of the generator should be reduced by operator or control action upon indication of a turbine trip. Such indication should come from a mechanically operated device such as a differential pressure switch across the turbine. See IEEE/PSRC Working Group Report [B23].

A.2.10 Overexcitation protection (24)

Overexcitation of a generator will occur whenever the ratio of the voltage to frequency (V/Hz) applied to the terminals of the generator exceeds 1.05 pu (generator base). Overexcitation of a transformer connected to the generator terminals will occur whenever the ratio of the voltage to frequency (V/Hz) at the secondary terminals (high voltage) of a transformer exceeds 1.05 pu (transformer base) at full load 0.8 pf or 1.1 pu at no load. See IEEE Std C37.91.

The overexcitation capability limits for the generator and the connecting transformer are shown in Table A.2 and also in Figure A.22. 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 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 Figure A.22. The type of curve and time dial should be selected such that the relay characteristic is faster than the generator and transformer capability limit. In this example, the transformer is the limiting equipment compared with generator.

Typical settings

Inverse time element
Curve type: Inverse square

$$t = \frac{0.003K}{\left(\frac{\mathrm{V/(Hz)}}{100} - 1\right)^2} \tag{A.27}$$

where t is in minutes.

Time dial: $K = 4$
Pickup: 106%

Definite time element

Pickup: 118%

Time Delay: 0.05 min

Table A.2—Overexcitation capability

Main transformer capability		Generator capability	
Time (min)	**V/Hz (%)**	**Time (min)**	**V/Hz (%)**
40	106.4	33	110
30	106.9	25	111
20	107.4	20	111.5
10	108.4	15	112.5
6	109.3	10	113.5
2	112.1	5	115.5
1	114.3	2	118
0.5	118	1	120
0.3	123.5	0.5	122
		0.2	125

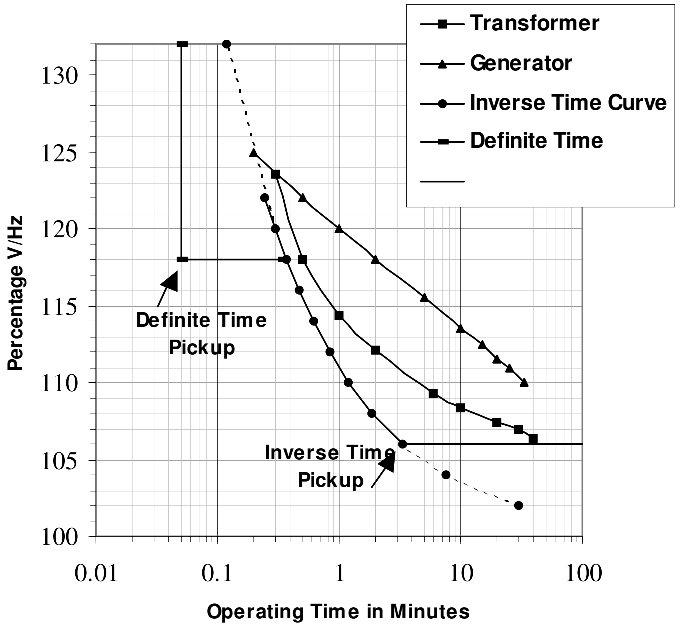

Figure A.22—V/Hz characteristic

A.2.11 Generator breaker failure (50BF)

There are several variations of the basic functional logic diagram (see Figure 4-52a) for the generator breaker failure protection. Essentially they all involve setting of two elements, current detector (CD) and a timer.

Current detector: Pickup of the CD should be more sensitive than the lowest current present during faults involving currents. The pickup value higher than the full-load current of the generator may provide added security in some schemes. However it is not essential to keep the pickup above the full-load current. One variation of the logic addresses open breaker flashover (see Figure 4-53).

Considering full-load current of 3.95 A and steady-state current of 3.03 A for terminal fault (see A.2.6), the CD pickup is set at 2 A.

Timer: Pickup time should be higher than the sum of generator breaker interrupt time and CD dropout time (if applicable depending on the logic used) plus a safety margin.

Breaker interrupt time = 5.0 cycles
CD dropout time = 0.5 cycle
Margin = 3.5 cycles

The timer pickup is set at 9 cycles.

A.2.12 Generator overvoltage protection (59)

Generator overvoltage is usually caused by sudden load rejection or failure of the voltage regulator. In the case of steam and gas turbine generators, this problem is mitigated by the fast response of the speed control system and the automatic voltage regulator.

Generators are usually designed to operate continuously at a maximum voltage of 105% of its rated voltage, while delivering rated power at rated frequency.

Sustained overvoltage above permissible limit may produce overfluxing (due to high V/Hz) and excessive electrical stress on the insulation system.

Protection of a generator from overvoltage may be provided by one of the following types of overvoltage devices:

a) Overvoltage relay protection function with instantaneous and inverse time characteristics:

   The pickup of inverse time element is set at about 110% of rated voltage. For the generator in Figure A.1, the rated voltage is 20 000 V. The corresponding VT secondary voltage is given by: 20 000/1666.7 = 120 V (assuming 59 function is connected to phase-to-phase voltage).

   Set the pickup at 110% of rated voltage, that is, at VT secondary voltage of 1.1 × 120 ≈ 132 V. Select a time-voltage curve from a typical family of curves so that the operating time will be about 2.5 s at 140% of the pickup setting.

   The instantaneous element pickup is to be set at 130% to 150% of rated voltage. Set the instantaneous pickup at 150% of the rated voltage, which is equivalent to a VT secondary voltage of 1.5 × 120 = 180 V.

b) Overvoltage relay function with two stages of voltage pickup and definite time delay set points:

   Setting of this type of overvoltage protection relay is usually based on the recommendation of the generator manufacturer.

   Typically, the first stage of pickup is set at 110% of generator rated voltage with a time delay of 10 s to 15 s.

For the generator in Figure A.1, set the low-set pick-up at 1.1 × 120 = 132 V with a time delay setting of 10 s.

Set the second stage pickup at 150% of generator rated voltage, that is 1.5 × 120 = 180 V with a definite time delay setting of 2 cycles to 5 cycles.

It is common practice to only alarm for overvoltage condition. For hydrogenerator application it is generally connected to trip. However, machine dielectric ratings and other overvoltage protection should be considered in this decision.

A.2.13 Generator undervoltage (27)

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 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. It is a common practice to alarm on undervoltage condition and not trip the generator.

Generator undervoltage may be detected and an alarm is generated so that the operators can take appropriate action to remedy the undervoltage condition. One of the following types of devices can be used to detect undervoltage condition.

a) Undervoltage relay with instantaneous and inverse time characteristics:

   The pickup of inverse time element is set at about 90% of rated voltage. For the generator in Figure A.1, the rated voltage is 20 000 V. The corresponding VT secondary voltage is given by: 20 000/1666.7 = 120 V (assuming 27 function is connected to phase-to-phase voltage).

   Set the pickup at 90% of rated voltage, that is, at VT secondary voltage of 0.9 × 120 ≈ 108 V. Select a time-voltage curve a typical family of curves so that the operating time will be about 9.0 s at 90% of the pickup setting.

   The instantaneous element pickup is to be set at about 70% of rated voltage. Set the instantaneous pickup at 70% of the rated voltage, which is equivalent to a VT secondary voltage of 0.7 × 120 = 84 V.

b) Undervoltage relay with two stages of voltage pickup and definite time delay set points:

   Typically, the first stage of pickup is set at 90% of generator rated voltage with a time delay of 10 s to15 s. For the generator in Figure A.1, set the low-set pickup at 0.9 × 120 = 108 V with a time delay setting of 10 s.

   Set the second stage pickup at 80% of generator rated voltage, that is, 0.8 × 120 = 96 V with a definite time delay setting of 2 s.

A.2.14 Over/under frequency (81)

The generator and turbine are limited in degree to abnormal frequency operation that may be tolerated. Steam and gas turbines are more limited or restrictive to abnormal frequency than hydrogenerators. At some point abnormal frequency may impact turbine blades and result in damage to the bearings due to vibration. It is important to consult turbine manufacturer and get turbine off frequency operating curves or limits. The frequency settings are selected within the specified range of turbine frequency limit. There are two types of frequency conditions occur on power system that may impact generators and turbines.

1) Underfrequency
2) Overfrequency

While the manufacturers turbine off-frequency limits should provide the basis for over/under frequency protection, additional criteria such as load shedding schemes or constraints imposed by coordinating councils should be considered. Generally, unit protection should be coordinated to accommodate system load shedding while not exceeding unit limitations.

A.2.14.1 Underfrequency (81U)

This condition may occur in the system due to sudden reduction in input power through loss of generator(s) or loss of key intertie (s) importing power. Island of generation with load may cause underfrequency when the amount of load exceeds the amount of generation.

Underfrequency operation for steam turbine example

Continuous operations = 59.5 Hz to 60.5 Hz

Restrictive operation for short time (up to 50 min) = 58.5 Hz to 59.5 Hz

Restrictive operation for short time (up to 10 min) = 57.8 Hz to 58.5 Hz

Restrictive operation for short time (up to 3 min) = 57.2 Hz to 57.8 Hz

Operation prohibited = 57.2 Hz and below

Typical underfrequency settings

The underfrequency load shedding setting in the systems is given as 59.3 Hz with a delay of 14 cycles.

The generator 81U relay should be set below the pickup of underfrequency load shedding relay set point and above the off frequency operating limits of steam turbine.

Trip set points

Element # 1

Pickup: 59.2 Hz, time delay = 10 min

Element #2

Pickup: 58.4 Hz, time delay = 1.5 min

Element #3

Pickup: 57.7 Hz, time delay = 30 s

Element #4

Pickup: 57.1 Hz, time delay = 0.167 s

An alarm setting of 59.5 Hz with a time delay of 10 s may be used.

A.2.14.2 Overfrequency (81O)

This condition may occur due to sudden loss in load or loss of key transmission lines exporting power. Typically overfrequency protection is provided by governor control system. Islanding of generation with load may cause overfrequency when the amount of generation exceeds the amount of the load. In some cases, overfrequency protection is not provided since the governor controls monitor the speed and respond with a runback signal. Protection for severe load rejection is provided by the turbine overspeed trip device(s) and as a backup 81O may also be set to trip during this condition.

Overfrequency operation for steam turbine example

Continuous operation = 59.5 Hz to 60.5 Hz

Restrictive operation for short time (up to 10 min) = 60.5 Hz to 61.8 Hz

Operation prohibited = 61.8 Hz and above

Typical overfrequency settings

Alarm settings:

Pickup: 60.6 Hz, time delay 5 s

Annex B

(informative)

Bibliography

B.1 General

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