INTERTIE PROTECTION OF CONSUMER-OWNED SOURCES OF GENERATION, 3 MVA OR LESS

A Report by the Power System Relaying Committee

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SCOPE

Intertie Protection of Consumer-Owned Sources Of Generation, 3 MVA or Less

The report discusses the power system protection considerations (other than surge protection) associated with the connection of small, dispersed sources of generation to utility distribution lines. Primary emphasis is given to detection of system disturbances or conditions that would require generator separation. Background information on the various types of utility distribution systems and small generators is provided to facilitate communication between utility engineers and owners of small generation sources. Primary emphasis is given to protection of the utility system, including consumers, from the possible adverse effects of the generation, but some possible effects of the power system on the generation (e.g., reclosing out of synchronism) are also discussed.

For those problems that can be solved by the use of protective relays, the paper makes suggestions about the necessary characteristics of relays and switching devices. Several specific examples are given for hypothetical small generation installations showing appropriate protective relaying and explaining the purpose of each device.

Complete protection of the DSG facilities, including the generators, power delivery systems, and auxiliary equipment, is not within the scope of this paper.

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1. INTRODUCTION

A substantial number of consumer-owned generating sources (also called dispersed storage and generation, or DSG) are being directly connected to electric distribution lines. These DSGs are generally driven by renewable energy sources such as water, wind, solar power, or biomass heat. They are either synchronous or induction generators, or dc sources connected to an ac system through inverters, with ratings from 5 to 3000 kVA.

This report is directed to any person involved in the installation, application, and operation of interconnected DSG systems. For the less technical reader, it can be used as a guide for discussions with his consultant.

DSGs, while providing economic and environmental benefits, can create economic, technical, legal, and safety concerns for the owners, the electric utilities, and other utility customers. This report will examine the problems that may be encountered and propose resolutions that emphasize electrical protection techniques. Protection methods are identified for the utility lines and substation, and for the interface.

The following potential problem areas need to be considered when interconnecting a DSG with a utility:

(1) <u>Safety:</u> Interruption of the utility supply may not de-energize a circuit if a DSG is supplying power to the same circuit; therefore, protection to other utility customers, the public and utility personnel is a paramount concern.

(2) <u>Protection of Equipment:</u> All equipment needs to be adequately protected within expected ranges of load, fault current, and voltages.

(3) <u>Detection of Faults:</u> All faults must be detected and cleared promptly. Circuits with multiple sources need to be carefully analyzed for possible reversals of line load currents, and for the effects on circuit protection and coordination.

(4) <u>Restoration of Service:</u> Although it is in the public's interest to restore normal service promptly, restoration of service by the utility after an interruption may cause damage to a DSG still connected to the circuit. Equipment installed to prevent reclosing if the line is energized may cause a delay in restoration of normal service and may not be acceptable to other utility consumers.

(5) <u>Quality of Service:</u> Interference with communication circuits, TV and radio reception, computer systems, etc. can be caused by some types of generators, inverters, and loads. Sustained over or undervoltage and flicker may also occur. These effects need to be controlled within acceptable limits.

(6) <u>Costs:</u> While the foregoing concerns need to be resolved, the cost of protection should be considered when evaluating the feasibility of the proposed DSG installation to ensure safe and reliable interconnections.

2. ENERGY CONVERSION SYSTEMS

Three possible types of electrical power generating equipment may be connected to utility circuits: rotating generators driven by a prime mover, photovoltaic arrays, and fuel cells.

2.1 Rotating Generators.

Rotating generators may be driven by a waterwheel, windmill, internal combustion engine, or steam turbine. All of these are able to drive a constant speed-controlled generator to match the 60 Hz utility frequencies. A constant speed-controlled prime mover may turn either a synchronous or an induction; while variable systems, such as those driven by wind, may use alternative methods to match system frequency.

(1) Synchronous Generators: A synchronous generator is capable of supplying load as an independent source with voltage and frequency control, as long as the load does not exceed the generator rating and prime mover capability. It can operate in parallel with other generators and share load with them.

(2) Induction Generators: An induction generator must be driven above the synchronous speed of the interconnected ac system. Except under very special circumstances, it is incapable of independent operation or voltage control. Since there is no exciter or field winding, the excitation must be supplied from the ac system, which must have at least one synchronous generator of a minimum value of capacitance that will be determined by the rating of the generator.

DSGs up to 25 kW are usually single-phase; larger units are usually three-phase.

For systems with highly erratic input power, such as windmill generators, the alternatives for interconnection are:

(1) Generate at dc, store the energy in a battery, and invert to ac as needed.

(2) Generate at variable frequency ac and convert to constant frequency ac. Generation at variable frequency permits the rotor speed to follow the wind for maximum output. The frequency change can be done by wave synthesizers, cyclo-converters, variable-ratio hydraulic transmissions, or conversion to dc and then inversion to ac.

(3) Generate at constant frequency ac and shaft speed by using a synchronous or induction generator. This type is usually driven by variable-pitch propeller blades to improve efficiency.

(4) Generate using a variable-speed synchronous generator. These use a wound field fed by a variable frequency, phase locked to produce the desired output frequency and phase.

2.2 Non-Rotating Dc Generation.

Dc power (from photovoltaic arrays, fuel cells, or batteries) can be converted to ac power by a solid-state inverter or several types of power conditioners. Those that interconnect with utilities need filters to shape the wave and remove frequencies in the audio range or higher. Inverters can have a self-contained frequency source or can use the utility frequency for control. However, inverters are limited in their ability to handle reactive current required by inductive loads. With a conventional inverter, the var capability is fixed by the size of the filter capacitors. Since inverters have little or no thermal storage capacity, fault current may damage the components, although some inverters have controls that prevent the supply of fault current.

3. TYPES OF DISTRIBUTION CIRCUITS

For the sizes of DSGs under discussion, the choice of location for the generator will be limited by the circuit that is available for interconnection. In addition to the wide range of generators and distribution lines, consideration must be given to the other consumers on the feeder, the types of loads, the distance from a substation, the reclosing practice, the alternate supply source, the sectionalizing devices, etc.

The responsibility for distribution circuit operation rests with the utility. Any special requirements for the DSG should not influence the type, quality, or class of service provided by the utility to other consumers.

3.1 Distribution Primary Circuit Configurations.

In this text, it is not practical to discuss all possible distribution circuit configurations. However, the following four configurations, which cover the most prevalent designs, are given to show the possible effects of DSG transformer connections.

3.1.1 Three-phase Three-Wire Ungrounded Distribution. These are typically 2.4 through 7.2 kV systems with single-phase loads and branches. Typical equipment includes circuit breakers with tripping and reclosing relays, circuit reclosers, sectionalizers, fuses, voltage regulators, capacitors, distribution transformers, and surge arresters.

The DSG should have a transformer connected phase-to-phase or three-phase, with protective devices. Other requirements may include visible break disconnecting devices, grounding connections, locking devices, access by utility personnel, and utility-standard construction and maintenance practices.

3.1.2 Three-Phase Three-Wire Unigrounded Distribution. These are typically 4.16 through 34.5 kV systems with the substation distribution transformer neutral grounded at the substation but with no neutral conductor on the circuit. Typical equipment is similar to Section 3.1.1.

The DSG could have a transformer connected phase-to-phase or three single-phase transformers connected in delta, with protective devices. There should be a method of detecting distribution voltage ground faults whenever the generator is interconnected. Other requirements are similar to Section 3.1.1.

3.1.3 Three-phase Four-Wire Unigrounded Distribution. These are typically 4.16 through 34.5 kV systems with the distribution neutral grounded at the substation and an insulated neutral conductor for the circuit. The substation transformer is either solidly grounded or grounded through a non-interrupting current-limiting device, such as a reactor. The single-phase loads are connected phase-to-neutral while the three-phase loads may be either phase-to-neutral or phase-to-phase. No load current is expected to flow through the earth back to the substation. Other typical equipment is similar to Section 3.1.1.

The utility must determine the type and connection of three-phase transformers for the DSG. A method is needed to detect ground faults at the distribution voltage level whenever the generator is interconnected. Other requirements are similar to Section 3.1.1.

3.1.4 Three-Phase Four-Wire Multi-grounded Distribution. This is the most prevalent type, at 4.16 through 34.5 kV. The neutral is grounded at the substation, at every distribution transformer, and is usually connected to the secondary neutral grounds to form a common ground. The single-phase loads are connected phase-to-neutral; the three-phase loads may be either phase-to-neutral or phase-to-phase. Some load current will flow in the earth. Typical equipment is similar to Section 3.1.1.

A grounded wye-delta connected transformer, with the neutral of the wye connected either to the neutral conductor or to ground, may not be permitted by some utilities. This decision may influence the DSG transformer secondary connection. If the transformer is grounded wye-grounded wye, the type of generator grounding (if used) will be important in evaluating fault current levels.

3.2 Secondary Circuit Configurations.

These consumer utilization voltage systems are typically within the range of 120 to 480 V. Most secondary circuits require a neutral conductor grounded at the distribution transformer and also at each user service entrance. Each of these secondary circuits may have a number of consumers in addition to a DSG. When the DSG is the only user of a transformer, the distribution systems described under Section 3.1 apply. The utility must determine whether the DSG can interconnect to a secondary.

Typical residential service is supplied from a single-phase distribution transformer. The secondary is a single-phase, three-wire circuit for 120/240 V service, or two-wire circuit for 120 V service.

Three-phase secondary service depends upon the type of service to be supplied. There are three main types:

(1) 208/Y120 V or 480/Y277 V with a grounded neutral conductor. This is a four-wire wye connection.

(2) 240 or 480 V three-wire with three phase conductors. In some installations, one of the phase conductors is grounded.

(3) Four-wire delta, in which three transformer secondaries are connected to form 240 V phase-to-phase delta, and where one of the transformer secondaries is center-tapped grounded to neutral to provide two 120 V circuits. The center-tapped transformer usually has a larger kVA capacity than the other two transformers.

A dedicated transformer may be required between the DSG and the point of interconnection to the utility distribution circuit.

3.3 Distribution Network Configurations.

Distribution network systems are generally used by utilities to serve high load-density areas and provide the highest level of service reliability. Distribution networks are of two main types and incorporate redundancy in the primary feeders, in the network transformer, and in the secondary circuits. By design both types will not allow power to flow out of the network back to the utility.

3.3.1 Grid Network. The secondary is connected into a continuous grid covering a large area. Network transformers with interlaced supply circuits are connected at various points throughout the grid.

3.3.2 Spot Network. These are designed to serve a single large customer. The secondaries of several network transformers are connected to a collector bus at a single location, rather than to a common grid. Spot networks are generally served from the same dedicated network feeders that serve the grid network. However, spot networks located outside a downtown area are usually served from general-purpose radial feeders.

4. DETECTION OF FAULTS

4.1 Distribution Protection Overview.

4.1.1 Fault Current. Typical distribution feeders are fed radially from a utility substation. In these feeders, all of the fault current for faults on the feeder, as well as the load current, will come from the substation. The magnitude of the fault current is determined by the impedances of the utility source; the transformers, reactors and feeder conductors; and for ground faults, the earth impedances. The addition of induction machines to a distribution system will contribute transient current to a fault; the amount contributed is proportional to the total kVA of the induction generators feeding the fault. Generally, for the sizes used by DSGs, the transient current added to a fault by these machines is negligible. Synchronous motors or generators, however, will increase the fault current level and reduce the current being supplies by the substation to the point of actually causing a reversal on some circuits.

The maximum and minimum values of fault current are an important consideration for any protective relaying scheme. Maximum values determine the interrupting rating needed for circii6 breakers, circuit reclosers, fuses, etc. Minimum current values determine the lower limit settings of overcurrent relays and protective devices to provide a high probability of detecting all faults.

On a radial feeder, all protective devices between the substation relays and the fault measure the same current if the substation is the only source. This simplifies the coordination of overcurrent tripping devices to interrupt the fewest number of customers. Ground fault coordination may be affected if feeders have other sources of ground current.

Sources of feeder fault current due to DSGs may affect relay coordination, equipment rating, and safety of utility personnel and the general public. The magnitude of fault current from these sources will depend upon the type, size, and number of generators, their impedances, and their location with respect to the fault and substation.

If the DSG contribution is large, the operation of the relays at the substation may be delayed due to a reduction in fault current from the substation. A more likely case is that of a high impedance DSG source located near the substation. Such a DSG contributes limited fault current until the utility circuit breaker opens, which may result in slow detection and sequential clearing of the fault. These multiple current source problems will apply to phase-to-ground faults if the DSG transformer is grounded at the feeder voltage.

4.1.2 Grounding. The majority of distribution circuits have the grounded neutral of the substation transformer secondary as the only source of ground current. A high phase-to-ground voltage on the non-faulted phases may result if such a circuit is back-fed by a DSG connected in delta to the distribution circuit when the substation breaker opens on a single-phase-to-ground fault.

The situation affecting single-phase loads fed by either of the ungrounded phases can be divided into three categories:

(1) The DSG may be so small that even under the lightest loads the user voltage will be no more than normal.

(2) The DSG may be of a size such that moderate overvoltage will exist for the time it takes for relays at the DSG to sense the fault and remove the DSG.

(3) The DSG may be of sufficient size to produce an overvoltage approaching 73% above normal. Under conditions of ferroresonance, voltages above 300% of normal are possible. User loads and utility lightning arresters may not be capable of withstanding such an overvoltage, even for 0.2 second.

Voltage relays, if connected to the high side of the DSG connection transformers, can detect the fault and trip in a fraction of a second. This will provide adequate protection for categories (1) and (2). To protect user loads under category (3), the DSG could be connected by transformers with the high side in wye with neutral grounded. This connection may cause sequential tripping of the utility and the DSG breakers, and it will probably be necessary to modify the entire fault relaying and sectionalizing on the feeder. The grounded wye connection is not always effective against ferroresonance.

4.2 Characteristics of DSGs That May Affect the Relay Protection Scheme.

4.2.1 Synchronous Generators. Synchronous generators can supply subtransient and transient fault currents that are considerably larger than their maximum load current.

Inverse-time overcurrent relays with voltage compensation are an effective means of detecting phase faults. These relays permit load current when the voltage is normal, but will operate at relatively small currents when the voltage is low, as it is during a fault. Time-current coordination with other overcurrent devices on the circuit may de difficult or even impossible, since these devices are selected to coordinate with the substation relays.

Three-phase DSGs require detection of ground faults at the distribution voltage level. If the DSG transformer provides a high-side ground current source, or if it can pass zero sequence current from the grounded generator, an overcurrent ground relay can be used. If the transformer is not a ground current source, such as one having a delta-connected high-side winding, some form of voltage detection may be applied.

A single-phase DSG is required to detect a ground fault only on the particular phase to which it is connected, and this can be accomplished with an undervoltage relay.

Certain types of synchronous generators will lose their field supply due to a close-in fault. Fault detection for these units can be accomplished by voltage-sensing devices or by modifying the generator excitation scheme to produce sufficient current for fault current detection. Using voltage and frequency relays on synchronous generators is an effective means to detect other abnormal conditions.

4.2.2 Induction Generators. Induction generators generally make a short-time contribution to a phase fault similar to an induction motor of the same size. The overcurrent relays normally applied for the protection of the induction generator may not be sensitive enough to operate on the current supplies to an external fault. However, when there are groups of induction generators, as with groups of motors, or if there is a large induction generator, the total fault contribution may become significant and should be included in fault studies.

Most induction generators are incapable of operating unless they parallel a utility system or other sources of excitation. However, it is possible for several induction generators and one synchronous generator to provide a self-sufficient power source. Since the possibility exists for an induction generator to maintain fault current flow, or to supply load as an island (described in Section 5.4), the detection of faults on the distribution line requires methods similar to those used for a synchronous generator.

An induction generator that has become separated from a utility may be connected to the proper amount of capacitance to allow sustained abnormal operation, which could be dangerous to the DSG and other circuit equipment. There is also the possibility that resonance between the magnetizing inductance of the generator and the connected capacitance may cause damaging overvoltages. Recent tests have shown that lightly or non-loaded induction generators can produce an immediate rise in voltage of two times normal or more. This level could damage surge arresters, even if no potentially vulnerable load was connected. Fast tripping of the generator by accurate and sensitive over-voltage protection will generally prevent damage to utility or consumer equipment.

Other tests have shown a slow rise (10% in ½ second) in voltage but an instantaneous upward change in frequency following separation from the utility, if the isolated load was less than the generator output. In these situations, the slip will decrease instantaneously as the load suddenly drops, yielding a higher frequency and a momentary increase in load as various motor loads speed up. As the motors reach their new speed, the voltage will climb. Without generator control, the voltage and frequency will continue to increase until the load has absorbed the entire generator output. For this case, tripping by accurate and sensitive overfrequency relays may be faster than with overvoltage relays.

4.2.3 Solid-State Inverters. Because of the very low thermal tolerances of semiconductors, most of these devices are designed to be incapable of supplying fault current more than about 20% above rated load current. Conventional overcurrent relays will not be effective for fault protection, although in some cases a voltage-compensated time overcurrent relay can be used

Inverters may be line-commutated, meaning the frequency control comes from the utility system, or forced-commutated from an independent local ac source. A single-phase inverter that is line-commutated may be effectively self-clearing, since it will turn off when fault conditions cause the ac voltage to collapse. However, three-phase inverters that are line-commutated may not be self-clearing unless there is a three-phase fault. To protect for all types of phase faults, these inverters and forced-commutated inverters should be treated as synchronous generators. Since, for many inverter controls, the output current (not voltage) is the regulated quantity, voltage-compensated overcurrent relays can be applied.

Line-commutated inverters should be applied with the assumption that there are other DSG generators on the same line and, therefore, the inverters will continue to function when separated from the utility. A relay detecting small changes in frequency or voltage could be used to remove the inverter to prevent it from producing an output when separated from the utility.

Forced-commutated inverters may continue to function when separated from the utility and can be removed by voltage sensing relays, since a small DSG will probably be overloaded. This overloading may not exist during periods of light load, however, or if other DSGs are connected to the same distribution circuit. Many inverters contain internal controls, which will shut down under most utility separation conditions; however, if sufficient capacitance is present, self-excitation is possible. It is also possible for one inverter to react with rotating machinery to form a self-commutating system. Until data is obtained proving otherwise, it should be assumed that self-commutated inverters are capable of feeding an isolated load.

The protection methods for inverters may be the same whether they are powered from photovoltaic arrays, batteries, fuel cells, or other dc supply. An isolation transformer is usually required to prevent any flow of direct current into the utility system in case of equipment failure.

4.3 Intertie Protection Requirements.

4.3.1 General Requirements. Protection must be provided for DSG installations to protect personnel, utility facilities, and equipment of other consumers from the abnormal voltage and frequency that may occur when the DSG is operating as an island. This protection must operate for short circuits, overloads, low or high voltage, and low or high frequency, and must prevent out-of-phase reclosing and energization of a dead supply line by the generator. The generator owner is responsible for the protection of his equipment, which is usually specified by his consultant or equipment manufacturer.

Intertie protection requirements are influenced by the size and characteristics of the DSG, along with the characteristics of the associated utility supply system. Similar units connected at different locations could have different protection requirements. An important influence on protection requirements is the expected performance of the dispersed generator should it become isolated with a portion of the utility system by operation of a sectionalizing device (see Section 5.4). If the generator can continue to carry the load of the isolated section, protection is required to assure that the voltage and frequency supplied are not outside acceptable limits. Also, reclosing of the sectionalizing device may need to be blocked to prevent possible out-of-phase reclosing. Separation of the generator is required prior to reclosing the supply line.

In the interest of safety of the general public and utility maintenance personnel, and in order to facilitate rapid restoration of normal power supply, operation of a DSG as an island serving other consumers is normally undesirable. In those cases where island operation is needed due to criticality of certain loads, it will be necessary for the DSG owner and the electric utility to jointly design a system to meet this objective.

4.3.2 Protection Schemes. The intertie protection schemes provided at a DSG will depend on the specific characteristics of the installation. In general, one or more of the following types of protection, as shown in Figures 1 through 7, could be applied. Any settings mentioned serve only as examples and should not be considered as recommended settings.

The purpose of protective relays is to cause the isolation the DSG from the utility system. Where this can be accomplished by more than one breaker, the specific breaker or breakers used depends upon the DSG owner's operating strategy (see Sections 6 and 7).

4.3.2.1 Undervoltage (27) – Instantaneous or Time Delay. Upon being separated with a portion of the system, a drop in terminal voltage can be expected from an overloaded generator or from one incapable of isolated operation.

Instantaneous undervoltage relays provide fast separation of the generator after the line to which it is connected (supply line) has tripped. Instantaneous operation may be required to separate the generator prior to reclosing its supply line, particularly when high-speed reclosing is used. It is desirable to set this relay as sensitively as possible without causing excessive nuisance operations due to faults on utility system facilities other than the supply line.

The delay undervoltage relays are required when the generator is capable of isolated operation. A setting of 90 to 95% of nominal voltage, reflecting the low voltage limit allowed for supply to customers, is generally applied. A one-second time delay should be sufficient to prevent incorrect operations on voltage dips caused by external faults.

4.3.2.2 Overvoltage (59) – Instantaneous or Time Delay. Should a generator become isolated from the utility system, excitation controls may not be capable of preventing voltage from increasing beyond acceptable limits. Excess capacitance will serve to increase the transient voltage level. Overvoltage relays are intended to sense a voltage rise beyond an acceptable level and to initiate machine separation.

Instantaneous overvoltage relay operation minimizes the possibility of equipment damage, since voltage may rise at a rapid rate. If instantaneous overvoltage relays are set above 110% to prevent excessive nuisance trips, a second complement of overvoltage relays may be added; one set between 106% and 110% with short a time delay and another that provides instantaneous protection set no higher than 150% of nominal.

4.3.2.3 Under/Overfrequency (81/U, 81/O) – Instantaneous or Time Delay. When operating in an isolated mode, generation speed control may not be able to maintain frequency within acceptable limits. Under/overfrequency protection provides an additional method of tripping an isolated unit to ensure that it does not supply other customers with incorrect frequency.

Underfrequency relays can also serve to separate a DSG from the faulted supply line after the source breaker has been tripped. Since a deviation of + or - 0.5 Hz indicates a major excursion, settings between 59.0 and 59.5 Hz may be used. If a relay with adjustable time delay is applied, the time delay should be set at minimum. On larger units, the setting may be selected to coordinate with underfrequency load-shedding relaying.

Overfrequency relays are applied when the generator is capable of isolated operation. A standard setpoint of 60.5 Hz provides the upper frequency limit an isolated generator is allowed to supply to other customers. Either instantaneous or time delay operation is acceptable, with adjustable delays set at minimum time, usually 0.1 second.

4.3.2.4 Voltage-Controlled or Voltage-Compensated Time Overcurrent (51V). Voltage-controlled or voltage-compensated time overcurrent relays sense the short-circuit current supplied by the generator and are used mainly on larger units. They provide excellent protection for phase faults and may be set to obtain selectivity with other inverse overcurrent devices. The relays are set to provide adequate converage for faults in the protected zone. The time delay is set to coordinate with other system protection devices. Specific settings will depend on the characteristics of the individual installation. Guidelines for setting both voltage-controlled and voltage-compensated relays may be found in Reference 13.3.

4.3.2.5 Battery/Dc Undervoltage (27dc) – Time Delay. This device monitors the dc control voltage used to trip the intertie circuit breaker. It will initiate tripping of the breaker if the control voltage fails below a predetermined value that indicates that this source of tripping energy is approaching the minimum level required for reliable operation.

4.3.2.6 Synchronism Check (25). This relay prevents paralleling a synchronous generator with the system unless the phase angles and magnitudes of the generator and system voltages are within specified limits. Otherwise, the DSG may be severely damaged if paralleled out-of-phase. Synchronism check relays are set to prevent synchronizing if the phase angle exceeds a maximum of 20^0, for example, or if the slip frequency exceeds a maximum of 0.25 Hz. These settings can vary over a wide range as a function of generator rating and transfer impedance. The synchronizing equipment is usually the property of the DSG owner.

4.3.2.7 Voltage Check (27). Voltage check schemes are used to prevent closing of a line sectionalizing device when voltage exists on the generator side of the device. In this application, the relay prevents the potentially damaging effects of closing out-of-phase. A voltage check scheme at the DSG is applied for paralleling control of induction generators.

4.3.2.8 Overvoltage/Undervoltage Ground (59N/27N). Figures 6 and 7 show how these relays are applied. When the primary of the DSG transformer is connected in delta, these relays will detect most primary ground faults.

If the generator can operate as an island, voltages greater than 2 p.u. can be developed within a few cycles; therefore this type of transformer connection may not be appropriate when island operation is possible.

4.3.2.9 Reverse Power (32). A single-phase relay may be used to detect an excess of balanced three-phase power from the DSG's bus into the utility system. This relay is not intended for use as a fault protective relay. Its purpose is the detection of an island condition by measuring the excessive power delivered by the DSG when the utility source is lost.

The sensitivity of the relay is set safely above the amount of power the utility has contracted to receive. Its trip output is sent to the DSG interconnection circuit breaker. A time delay on the order of ½ second should override system faults, and a longer time delay would allow time for operator intervention.

4.4 Examples of Faults.

Consider a typical utility distribution system shown in Figure 8. Assume that the DSGs are three-phase synchronous generators. Utility customer Z has a DSG unit normally interconnected with feeder 3 of Station C with an alternate supply from feeder 7 of Station D. Customer Z has a delta-connected transformer at 12 kV. Customer X is single-phase and Customer Y is three-phase. Feeders 4 and 5 are similar, and may or may not have DSGs.

4.4.1 Three-Phase Fault or Phase-to-Phase Fault at F1. This fault must be cleared by opening circuit breaker 3 at Station C and circuit breaker 6 at Customer Z. Automatic reclosing of circuit breaker 3 should be delayed to allow the relays at Customer Z to operate. Phase fault tripping of the circuit breaker of Customer Z could be initiated by directional distance, overcurrent, undervoltage, or over/underfrequency relays. A voltage check scheme should be added at breakers 3 and 7 to prevent these breakers from being reclosed unless the line is dead.

4.4.2 Single-Phase-to-Ground Fault at F1. Station C is the principal source of ground fault current for this distribution system, and circuit breaker 3 will be tripped by the fault current. Customer Z is required to trip if the generator is interconnected in order to de-energize the feeder. Since Customer Z will not supply current to a single-phase-to-ground fault, voltage relays, connected as shown in Figures 6 and/or 7 may be applied. For large units, a transfer-trip scheme may also be employed. Transmitters will be required a both Stations C and D. Fault clearing at Customer Z will usually be sequential, i.e., breaker 6 will probably not open until after breaker 3 opens, since there will not be enough zero-sequence voltage to operate the Customer Z relays. Tripping of breaker 6 will be further delayed if there are additional sources of zero-sequence current, as would be the case if grounded-wye/delta transformer banks are connected to the circuit.

4.4.3 Phase-to-Ground fault at F4. Customer W transformer is a ground fault current source at 12 kV. The transformer can be grounded-wye at 12 kV with a secondary connected in delta, or the secondary can be grounded-wye and the generator also grounded. Any or all of these wye-connected windings may have a neutral impedance, which will be subject to heating from any unbalanced load on the four-wire 12 kV distribution feeder. An overcurrent relay, supplied by a ct in the transformer primary neutral, or by the residual current from phase cts, will operate for phase-to-ground faults. Unless properly coordinated, this relay will also operate for external ground faults such as on Feeder 7. In addition, if the transformer has 12 kV fuses that are selected for low-side coordination, they may blow for faults on Feeder 7 that are not promptly cleared, whether the DSG is running or not. Therefore, the ground relay setting should be coordinated with the fuses.

4.4.4 Faults at F2. All faults at F2 should result in the tripping of circuit breaker 4. It is preferable that circuit breakers 6 and 3 not trip for this fault. If the instantaneous overcurrent tripping units of circuit breaker 4 are out of service or automatically disabled after the first trip, the voltage relays at Customer Z should be delayed so they will coordinate with the time overcurrent relays on circuit breaker 4.

4.4.5 Faults at F3. For the system shown, it is unlikely that a 3 MVA (or less) generator can carry Station C as an island after circuit breakers 1 and 2 open. If there is any possibility that Customer Z can keep the 115 kV energized, with or without a fault, protection must be installed at Station C to detect this condition and trip the appropriate circuit breaker to de-energize the fault. The protection for ground faults at F3 may be by 115 kV VT or CCVT as shown in Figures 6 and 7.

4.5 Other Considerations.

4.5.1 Transfer of Feeder to Another Source. An alternate source to Customer Z is through circuit breaker 7 at Station D. Any modification required at Station C due to the DSG should also be applied to Station D. If there are several alternate sources, it may be more practical to require that the DSG disconnect when any alternate source is in service.

4.5.2 Sectionalizing of a Feeder. Automatic sectionalizing devices are not shown in Figure 8 between circuit breaker 3 and Customer Z. Single-phase devices, such as circuit reclosers or fuses, may cause damage to a three-phase generator or motor if one phase opens. The owner of such a generator or motor can apply local protection or negotiate with the utility to eliminate fuses and single-phase switching. Local protection should also operate for an open conductor on one phase.

Single-phase sectionalizing equipment should not be installed on the portion of circuit between Station C or Station D and Customer Z. Three-phase circuit reclosers located between circuit breaker 3 or circuit breaker 7 and Customer Z may be equipped with a voltage-check scheme to inhibit reclosing if the DSG is keeping the feeder energized. A transfer-trip system would improve protection and may be installed at additional expense.

5. DETECTION OF ABNORMAL NON-FAULT CONDITIONS

There are a number of other abnormal (non-fault) conditions which must be detected to minimize customer outages, equipment damage, and the possibility of personal injury. These usually require tripping all local infeed, including the DSG unit.

5.1 Under/Overvoltage and Under/Overfrequency.

Voltage and frequency constraints are critical factors that determine whether or not the DSG is operating acceptably. The acceptable voltage and frequency range, as specified by ANSI Standard C84.1 for customer service, and the operating practices of the utility are the controlling factors.

A variation from the acceptable ranges of voltage and frequency is the primary method by which large differences between generation and load can be detected. For instance, if the utility's source is severed from the feeder where a rotating type DSG is located, one of three things will occur:

(1) If the remaining load is greater than the isolated generation, the DSG will decelerate causing a decrease in frequency and probably a decrease in voltage.
(2) If the load is less than the generation, the opposite action will occur. Fast governor and excitation controls are needed to prevent overvoltage and overspeed damage.
(3) If the load is equal to the generation, at least temporarily, the frequency and voltage may remain within acceptable limits.

When there is no fault on the circuit, and the local generation nearly matches the load, it is possible for the circuit to operate as an island for an indefinite period of time. The settings of the voltage and frequency intertie relays determine the boundaries of the permitted operation, or "window", and deviations will cause the DSG to trip after some time delay.

For the detection of an island condition, a frequency deviation window of 1.0 Hz (59.5 to 60.5 Hz) is adequate, with a time delay as short as 0.1 second. The actual relay settings will be specified by the host utility.

The settings on the voltage relays will be determined by the utility's standards of acceptable voltage range for the location of the DSG interconnection. The time delay may be inverse time or definite time, but should be long enough to override voltage dips during faults on other feeders. Both time and voltage settings may have to be modified after field experience.

5.2 Out-of-Step.

It is possible for a rotation shaft-type DSG to become out-of-step with the utility system under certain conditions, such as a fault on another feeder or a sudden change in load. The DSG may be severely affected by an out-of-step condition, whereas the utility system remains steady. The adverse effects as seen by the utility customers may include over/undervoltage, over/underfrequency, harmonics, and flickering. The DSG may have a high pulsating current, which may be damaging to the DSG and associated equipment.

An overcurrent relay that does not have instantaneous reset (electromechanical) can be expected to operate after several pulses. Since an out-of-step generator is running at an average frequency that is higher or lower than the system, a frequency relay may operate. The frequency should be measured at the generator terminals to detect an out-of-step operation, since the feeder will probably remain at the utility frequency. However, the voltage at the generator terminals may be a mixture of two frequencies, as the DSG voltage pulses along with the frequency. For small DSGs, a fast operating reverse power relay may detect out-of-step operation since power will flow in and out of the DSG generator.

5.3 Loss of Excitation.

Generally, induction generators and inverters operate without their own source of excitation and must receive reactive current from the system or from capacitors. Upon a complete loss of a source of excitation, the DSG voltage may rapidly deteriorate to zero, with typical time constants of one to three cycles. The undervoltage relay will then operate to trip the unit.

On the other hand, most synchronous generators are equipped with an exciter and a voltage regulator. When partial or complete loss of excitation occurs, reactive current will be supplied from the system. If the system has available reactive capacity to maintain reasonable voltage, the generator will speed up and continue to operate as an induction generator. If the voltage cannot be maintained, the undervoltage relay may operate.

5.4 Islanded Operation.

For the purposes of this publication, the term "island" is used to describe the situation in which the DSG is feeding an unfaulted isolated utility customer load or loads. Since synchronous generators do not require interconnection with a utility system to operate, they may be capable of supplying part of the utility load if separation occurs somewhere between the DSG and the source substation. These installations can be divided into three categories:

(1) An installation, such as an industrial plant or hospital, where the primary purpose of the generator is to feed continuous power to the facility when the tie to the utility is interrupted. Operating such a facility as an island is desirable, but such plants must be designed so that the voltage and frequency excursion is within acceptable limits when separation from the utility occurs. Synchronizing facilities, either automatic or manual are used whenever the connection to the utility is reestablished and are usually owned and operated by the DSG owner.

(2) Any radial distribution line where an interconnected DSG is capable of supplying the power requirements of the entire line and its load. However, only certain types of DSGs would be capable of providing frequency, voltage and power factor control.

In most instances, the separation from the utility will be initiated by a distribution line fault, which will persist until the DSG breaker opens. An island may also be formed when the feeder breaker is tripped due to a fault in the source substation, or as the result of a transmission fault, such as F3 in Figure 8.

Because of the possibility of forming an island, it may be necessary to assure tripping of the DSG before reclosing the utility breaker. Reclosing of the utility breaker could damage the DSG if closed out of phase. As previously stated, it is normally undesirable to operate the DSG as an island serving other utility customers.

(3) In special instances, it may be desirable to establish a successful island of a radial line. An example might be a resort village fed by a single long distribution line. The isolation of the village and provision for operation as an island must be carefully designed using techniques similar to those used in (1).

Of course, island operation can only be acceptable when there is no risk to other utility customers and where they can receive the equivalent to utility service. This requires not only the same phase configuration (three-phase generator for three-phase load), but the proper transformer connections to supply the distribution load in the same manner as the utility. For instance, a DSG connected phase-to-phase should not supply a four-wire multigrounded feeder. Island operation also would require that the frequency and voltage stay within narrow limits set by the utility (with regulatory body approval). Deviations beyond these limits should be detected by relays, which would open the DSG interconnection.

Note: Due to safety and power quality concerns, most utilities will not permit DSGs to remain connected to isolated feeders under any circumstances. In some instances, this may require installation of a transfer-trip system to make sure that a DSG is promptly disconnected when the source substation breaker opens. See Figure 3.

6. SWITCHGEAR

Connection of the DSG to a utility system may impose requirements on switchgear beyond those ordinarily found at consumers without generation. These requirements include higher interrupting duty, synchronizing capability, and out-of-phase switching capability.

6.1 Switching and Fault-Interruption Devices.

6.1.1 Contactor-Transfer Switches. Contactors are designed to repeatedly establish and interrupt an electric circuit. The interrupting capability of a contactor is somewhat more than its load current rating. Contactors are applied in conjunction with a separate fault-interrupting device, generally fuses. They can be controlled by relays and frequently have a magnetic undervoltage release that causes them to open on loss of voltage.

Transfer switches are also designed for frequent operation, can energize loads by transferring them to alternate sources, and can carry large currents for a short time. Their withstand current rating pertains to their ability to withstand the magnetic and thermal stresses of high fault currents until the fault is cleared by a protective device. The protective device is usually located externally, although some types of transfer switches do include integral overcurrent protection. The latter have an interruption rating which should not be confused with the withstand rating.

With proper application, a contactor or transfer switch can be used by the DSG for synchronizing and protection. Many contactors, however, have load-side terminals, which are accessible and can be energized when the contactor is open. Care should be taken to protect personnel from injury.

6.1.2 Circuit Breakers. Circuit breakers are not made for frequent operations or a repetitive duty cycle. They are available for all possible voltages and for a wide variety of ratings; and are capable of making, carrying, and breaking load currents and fault currents. Power circuit breakers are normally equipped with separate electrically-operated close and trip coils which can be energized manually or by various control methods. Some are equipped with direct tripping attachments that sense circuit breaker overcurrents and function to trip the breaker. In molded-case breakers, the sensor is an integral part of the breaker.

Direct acting circuit breakers are divided into two types:

(1) Low voltage power circuit breakers are small, compact, rugged devices that have a stored energy operating mechanism and an overcurrent sensing device which is usually magnetic or solid state.

(2) Molded-case beakers are small and compact, and contain a thermal device, a magnetic device, a combination of these, or solid-state sensors that operate the spring-loaded contacts. The interruption time is between 8 and 16 ms. Where available short circuit current exceeds the breaker rating, current-limiting fuses may be installed in series with the breaker. Molded-case breakers are not generally suitable for repetitive switching operations.

6.2 Requirements for Switchgear.

6.2.1 Interrupting Capability. The requirements for utility switchgear will probably not be affected by the addition of a single generator of 3 MVA or less on the distribution system, but other devices near the DSG location, such as fuses and circuit reclosers, may need to be changed.

6.2.2 Synchronizing Capability. Synchronizing is normally the responsibility of the DSG owner. Circuit breakers used for synchronizing must have a short and consistent closing time. In addition, the circuit breaker must have the dielectric strength to withstand the phasor sum of the voltages across the contacts prior to paralleling. It should be noted that there may be more than one circuit breaker that can be used for synchronizing, depending on the general circuit arrangement and where separation could occur.

6.2.3 Out-of-Phase Interrupting Capability. The use of synchronous generators will impose out-of-phase switching duty on the circuit breaker that is opened to break the interconnection. The most severe duty occurs when the interruption takes place when the two systems are 180^0 apart. In this case, the steady state recovery voltage is twice the normal phase-to-ground voltage, provided both systems are effectively grounded and the poles open simultaneously. Other conditions may produce higher rates of voltage recovery across the dielectric in the gap between systems.

Present standards do not require general purpose circuit breakers to have an assigned out-of-phase switching current rating. If such a rating has been assigned, it will normally be 25% of the rated (symmetrical) short-circuit current. The ANSI Standards C37.04-1979, C37.06-1979 and C37.09-1979 recognize that the capability may need to be demonstrated, and test procedures are given for the 25% current.

6.3 Control Power.

Control power for contactors usually is obtained from the contactor circuit supply voltage, which, for a DSG, would be the utility source. A loss of this control power source should disconnect the DSG from the utility circuit, with or without time delay.

Power circuit breaker close and trip coils can be operated by ac or dc. A dc source provided by a storage battery with charger is considered the most reliable. However, batteries require regular inspection and maintenance. Therefore, if is advisable to monitor the dc voltage, and either alarm or tip the circuit breaker if the dc voltage approaches the minimum required to trip.

A capacitor trip is a form of control where the energy for tripping is stored in a capacitor by rectified ac. The capacitor must be recharged after each operation and the circuit breaker prevented from closing until the capacitor is adequately charged.

6.4 Switching Device Location.

The contactor or circuit breaker at many DSG installations may be connected at B in Figure 9, with or without circuit breaker A. This means that faults on the utility system, faults on the generator, or abnormal conditions will result in opening B. If the DSG unit can independently supply load at the same location, consideration should be given to the installation of circuit breaker A for added operating flexibility.

Device B would be operated for normal synchronizing of the DSG and for interruption and isolation of a faulted generator. The main device A would be operated for the loss of the utility source and permit the continued supply of loads C by the generator. Isolation of the DSG due to utility faults or abnormal conditions could be accomplished by opening either A or B, depending upon whether the load should be left on the utility or the DSG. In some cases the loads can be separated and connected to both sources. Therefore, synchronizing capability is desirable at both A and B to give flexibility of operation.

Interlocks should be provided to open A for utility problems only when the DSG is interconnected. These interlocks can be used to supervise the operation of frequency and voltage relays, and to block transfer tripping signals from the utility. When the generator is not running, station protection will be similar to other customers of the utility.

7. RESTORATION OF SERVICE

After separation of a DSG from the utility system, restoration can be accomplished in a manner similar to the original interconnection. However, the process will differ depending on where the separation took place, where the interconnection can be restored, and whether the restoration will be by automatic or manual control.

Synchronizing is necessary with synchronous and possibly other types of generators. Even when synchronizing is not necessary for interconnection, the voltages and phase angles on either side of the circuit breaker need to be within reasonable limits when the circuit breaker closes to prevent damage to the circuit breaker, the DSG, or other equipment.

The preferred place to synchronize is at the DSG generator circuit breaker where the speed and voltage controls are available. An alternate location is a low- or high-side circuit breaker on the transformer that is used to interconnect the DSG with the utility. This latter arrangement allows the generator to be carrying some load before synchronizing. Ordinarily, the utility will not allow the DSG to close into a dead distribution line. Detection of all three-phase-to-ground distribution voltages can be used in a permissive relay to supervise connection of the DSG.

Many utilities have automatic reclosing facilities at distribution substations. Both automatic and manual closing should be blocked if the feeder is energized. To avoid possible damage to the DSG, operating procedures and/or the use of additional equipment can assure that the DSG is removed before the utility recloses.

8. COMMUNICATION

Apart from other communication channel requirements, it may be desirable to provide a transfer tripping channel between the utility substation (or other sectionalizing point) and the

DSG location. An example of this is shown in Figure 3. The utility relays will detect line faults and transmit a signal to trip the DSG when the utility feeder circuit breaker is tripped. The DSG relays will provide backup protection. The scheme could also prevent accidental islanding caused by the unintentional opening of the substation circuit breaker when there is no feeder fault. It is also possible to use a communication channel to detect islanding by sensing a loss of synchronism between the voltage at the DSG and the utility system.

9. OPERATING CONSIDERATIONS

9.1 Voltage Regulation.

Voltage variations on distribution circuits need to be regulated within acceptable limits as the loads and generation levels change. These limits and actual voltages will vary with the territory served, such as urban or rural; the class of load, such as industrial, commercial, or residential and public service commission regulations. Most distribution feeders serve all types of load, but one dominant class will usually determine the voltage levels and regulation for that particular feeder.

Where a DSG is connected to a substation bus, the bus voltage can be allowed to vary in response to the DSG output so long as voltage regulating transformers are used between the bus and the feeder. The variation in bus voltage is similar to a change in the substation supply voltage. If the DSG is between the regulator and the load, it will cause improper voltage regulator action, because the voltage compensator will measure the actual line current; but if the DSG is at the load center, the feeder voltage compensation will perform correctly.

If the point of interconnection is sufficiently distant from the substation, the effect of the DSG on voltage will be directly related to DSG power factor. If the voltage effect is significant, limits on power factor might be required to maintain proper feeder voltage. With the conventional synchronous generator, var control can be accomplished by controlling the field with a voltage regulator on the exciter. When an induction generator or static power converter is installed, switched capacitors may sometimes be used to control the voltage at the DSG.

The connection of unfiltered square-wave inverters to a distribution circuit can cause an excessive voltage distortion. To prevent this, the total kVA of such unfiltered inverters connected to any one distribution line may have to be limited.

9.2 Flicker Production.

Flicker is a low frequency fluctuation in voltage that can be observed through changes in intensity or color of illumination. It is usually related to sudden load changes that produce a voltage change, such as occur when firing an arc furnace or during motor startup. Flicker can also be caused by the hunting of a voltage regulator. With DSGs, however, flicker may be caused by fluctuations in driving power, such as in a photovoltaic system when clouds pass over the sun or at wind turbines with changes in wind velocity. A voltage change will occur if the DSG is suddenly turned on or turned off, but this is not defined as flicker unless repeated frequently. While flicker can be an irritation to customers, it should have no effect on protection.

9.3 Harmonics and Interference.

The voltage waveform produced by rotating generator equipment is sinusoidal, balanced, and of a single frequency. It is generally not considered a source of harmonics. DSGs employing static frequency converters to interconnect with the utility, however, may produce harmonics in their output waveform. These distortions are very similar to those produced by thyristor-controlled motor loads. As with thyristors, part of the distortion is produced by the system commutating notches. The frequencies produced are in the mid-audio frequency range and can cause telephone interference (electromagnetic interference). FCC standards set limits on signal and noise levels that are radiated.

Harmonics have been shown to adversely affect electrical equipment, as well as the operation of protective relays. The DSG protection system should be designed to tolerate the expected maximum level of harmonics.

9.4 Ferroresonance.

Ferroresonance is a special case of resonance, which can occur when a non-linear inductive reactance is connected in series or parallel with a capacitive reactance. In instances of ferroresonance involving distribution facilities, the inductive reactance will be the magnetizing reactance of single-phase or three-phase transformers. The capacitive reactance will be the conductor-to-sheath capacitance of primary cable and/or any shunt capacitors used on the system.

One form of ferroresonance can occur as the result of an opening or closing of one or two phases of a source supplying the single-phase or three-phase transformers. For this condition, the capacitance of the open phase on the source side of the transformer is energized through the magnetizing reactance of the transformer. Since in this case the reactance and capacitance are in series, this type of ferroresonance is sometimes referred to as series ferroresonance.

The asymmetrical opening or closing may be due to switching with single-pole devices such as cutouts, to conductor breakage, or to a fuse blowing. Since ferroresonance disappears or does not occur when all three phases are opened or closed, the probability of occurrence will be minimized when three-phase devices are used for switching. Note that the overvoltage build-up takes a finite period of time, which is the reason that switching with a three-phase device will usually be satisfactory, even though the pole openings may not be simultaneous.

A second type of ferroresonance can occur during an islanding condition. Under normal three-phase operation, the magnetizing reactance of the transformer is in parallel with the system capacitance and, with the transformer voltage being held below the saturation point, no problem occurs. During an islanding condition, however, there may not be sufficient voltage regulation in the island to hold the voltage below the saturation point. As the transformer(s) saturate, there will be an interchange of energy between the system capacitance and the highly nonlinear magnetizing reactance of the transformer(s). The rapid changes in transformer flux during this period can produce high system overvoltages. Since in this case the reactance and capacitance are in parallel, this second type of ferroresonance is sometimes referred to as parallel ferroresonance.

This type of ferroresonance, as well as the series type, may be accompanied by abnormal voltage, low or high, across the transformer terminals and from terminals to ground. High abnormal voltage due to ferroresonance will manifest itself by abnormal transformer sound and, if sufficiently high, by equipment damage.

The probability of both types of ferroresonance occurring is somewhat unpredictable as both depend on such factors as the cable lengths, the amount of system capacitance, the connection and saturation characteristics of the transformers, the amount of load, etc. In addition to the use of three-phase switching devices mentioned previously, the probability of occurrence can be minimized by extending the primary neutral and connecting all transformer windings from phase to neutral, and by the use of high-speed relay protection to shut down the system for an islanding condition.

10. COST OF PROTECTION

The protection for DSGs can be divided into two major categories: the protection of the generation source and the protection of the utility system from the effect of the generation source. Charges to the DSG owner for protection costs need to be reasonable and legitimately incurred. At the same time, the overall interconnection must meet the intent of PURPA, as well as serve the public interest.

10.1 Protection of the DSG Equipment.

Even though the DSG owner has the responsibility to fully protect his generator and other equipment, the utility has considerable control over the cost of this protection by virtue of its responsibility to ensure a safe and reliable interconnection. In the absence of any standards by a state regulatory authority, the utility may have the right to specify the protection to be used by the DSG owner, or to approve of the protective equipment selected by the owner. While restraint and logic should be used in establishing protection requirements, the degree and quality of protection of the DSG should be consistent with that applied on the interconnected system. Protection for small DSGs could be a significant percentage of the total cost of the generating equipment. However, the dominant factor which affects the cost of DSG protection is the electrical capacity of the generator or inverter equipment, since fault current magnitude determines the degree and sophistication of protection and the rating of interrupting devices.

10.2 Protection of the Utility System.

The cost of the protection required on the utility system due to DSGs can be designated as interconnection costs. These costs can be divided into two parts: those associated with the protection at the point of interconnection (the intertie), and those associated with the protection changes and additions which must be made at other locations on the interconnected system.

10.2.1 Protection of the Utility Intertie. As with generator protection equipment, the degree of protection required at the point of interconnection is directly related to the size of the generator. Increased short-circuit contributions from larger units and increased investments by the utility in equipment require sensitive and fast protective schemes, which are usually more expensive. The utility must comply with the intent of PURPA but still be careful not to jeopardize safety and service to the distribution line. The following functions must be performed at the point of interconnection:

(1) Tripping for all distribution feeder faults.
(2) Isolating faulted DSG equipment from the utility system.
(3) Preventing any reduction in quality of service to utility customers. This includes abnormal voltage or frequency, flicker or excessive harmonics.
(4) Preventing a DSG from energizing a dead utility circuit.

In addition, some utilities may require that a communication channel be installed to disconnect the DSG for a fault on the utility system or the opening of the sectionalizing device. This could significantly increase the protection cost. There may be some cost reduction possible if several DSG s are sharing the same communication facilities.

10.2.2 Protection of the Interconnected Utility System. Protective equipment or operating equipment changes on the utility system may be required due to the connection of a DSG, thus increasing the cost of interconnection. Some of the modifications which might need to be made to the utility system are:

(1) Changing the reclosing control of the preferred and alternate source substation feeder circuit breakers**.**
(2) Increasing protective device capability due to increased fault current.
(3) Changing distribution fusing or sectionalizing due to coordination problems with higher fault currents.
(4) Installing a directional ground relay at the substation if the DSG transformer is a large ground source, or a zero-sequence voltage relay if the substation power transformer is ungrounded on the high side.
(5) Removing fuses or switching devices between the substation and the DSG to prevent single phasing or to reduce the probability of an island condition.
(6) Replacing surge arresters and transformers with those having a higher basic insulation level.
(7) Installing larger conductors or additional circuits because of higher steady-state current.
(8) Adding power factor correction facilities.
(9) Converting a single-phase branch to three-phase.

11. CONTRACTUAL REQUIREMENTS

11.1 Quality of Equipment and Workmanship.

It is essential to have properly designed installations that are constructed in accordance with good engineering practice, the National Electrical Safety Code, and other applicable codes and standards. Since the interface equipment will have a direct bearing on the utility operation, the utility needs to clearly define any equipment requirements or maintenance requirements and make these known to the DSG owner early in the negotiation.

11.2 DSG Owner/Utility Communications.

For any proposed DSG that will be operated in parallel with an electric utility, it is essential that early and adequate communication be established between the DSG owner and the utility. The utility should furnish a list or requirements for parallel operation, and both parties should come to a common understanding of duties and responsibilities for each party in the following areas:

(1) Personnel to furnish and receive information.
(2) Specification of interface equipment, plans and drawings.
(3) Utility review and approval of proposed installation design.
(4) Responsibility for scheduling, inspection, testing, and acceptance.
(5) Requirements for periodic maintenance and testing, including responsibility, frequency, and reporting.
(6) Determination and application of protective relay settings.
(7) Special utility operating conditions which could restrict DSG operation, such as supply from an alternate source.
(8) Utility access to interface equipment, particularly switching and grounding devices.
(9) Leasing of a telephone circuit or other communication service, if needed.
(10) Procedures required to analyze and correct interference to the service to other utility consumers discovered after operation commences.

12. CONCLUSION

Close cooperation between the utility and the DSG owner, and serious efforts to find resolutions to the potential problems that may be encountered when interconnecting a DSG will permit safe and effective parallel operation of dispersed generation.

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Various policy and technical studies on hydroelectric power are available for a small fee from the U.S. Government Printing Office, Washington, DC 20402.

14. GLOSSARY AND ABBREVIATIONS

Cogeneration: Any installation that provides a combined usable output of thermal (heat or steam) and electric energy.

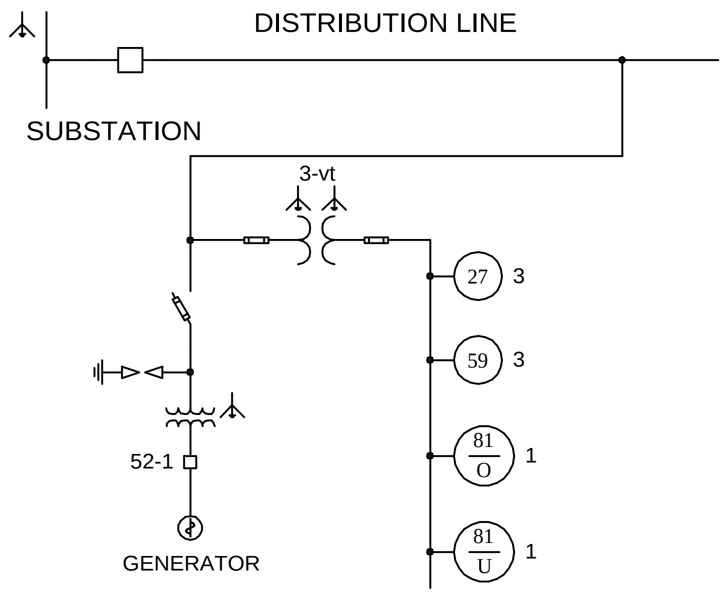
DSG: An acronym for "Dispersed Storage and Generation" used to describe an electric utility customer that generates power that is used on site and/or fed back to the utility under a contract usually falling under PURPA.

Island: The continued operation of one or more DSGs supplying power to themselves and other nongenerating customers with all interconnection ties to the utility open. The formation of an island may result from correct or incorrect operation of protective relays and other control equipment. The power quality may be technically acceptable to the island and undamaging to utility interconnection equipment, yet may not necessarily be within limits set by state statutes or utility standards.

Qualifying Facility: Any small power producer or cogeneration facility that qualifies under the PURPA legislation.

A	ampere
ac	alternating current
ct	current transformer
dc	direct current
DNR	Department of Natural Resources
DSG	dispersed storage and generation (or Dispersed Sources of Generation)
FCC	Federal Communications Commission
FERC	Federal Energy Regulatory Commission
Hz	hertz
kHz	kilohertz
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
MHz	megahertz
MVA	megavoltampere
NEC	National Electrical Code
NESC	National Electrical Safety Code
PCU	power conditioning unit
ppm	parts per million
PURPA	Public Utilities Regulatory Policies Act of 1978
PV	photovoltaic
QF	qualifying facility under PURPA
URD	underground residential distribution
V	volt
VA	volt-ampere
V/Hz	volts per hertz
var	voltampere-reactive
vt	voltage transformer
W	watt
WECS	wind energy conversion systems

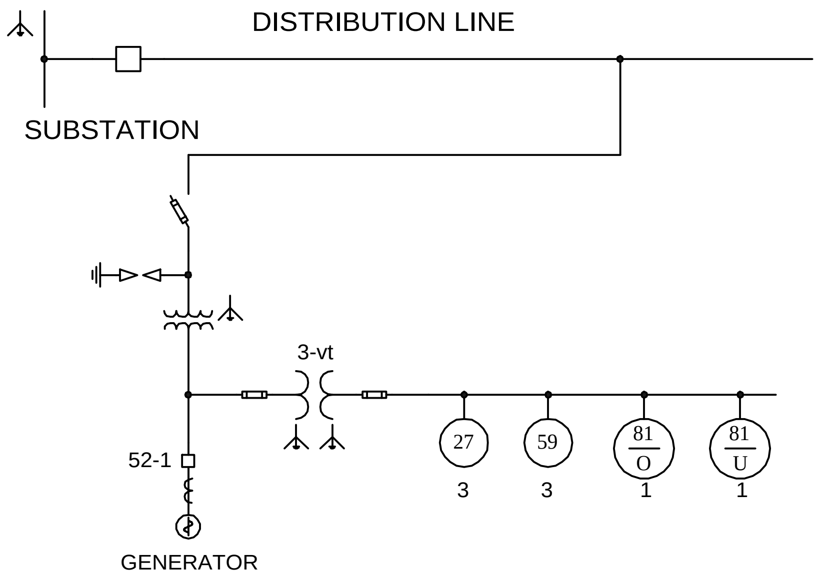
15. FIGURES



27 UNDERVOLTAGE
52 CIRCUIT BREAKER
59 OVERVOLTAGE
81/O OVERFREQUENCY
81/U UNDERFREQUENCY

Primary Supply to Relays

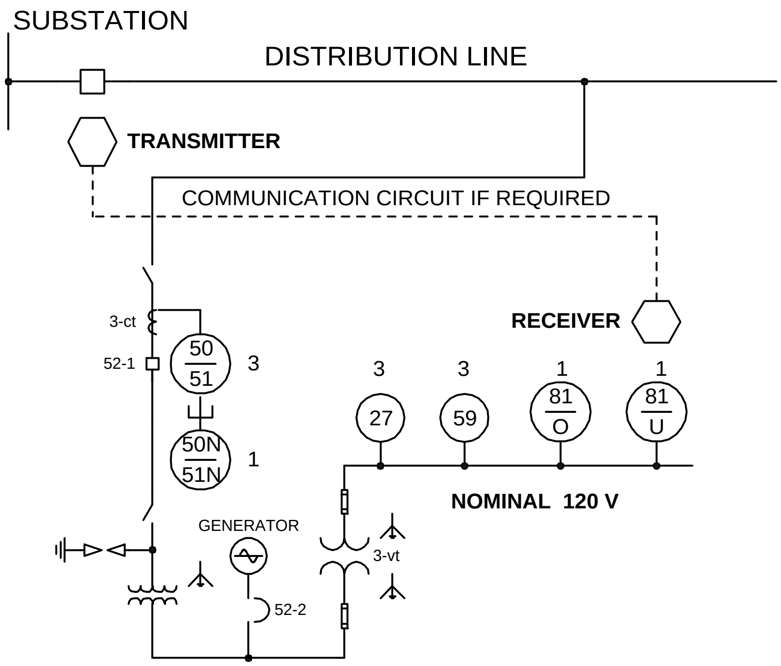
FIGURE 1



27 UNDERVOLTAGE
52 CIRCUIT BREAKER
59 OVERVOLTAGE
81/O OVERFREQUENCY
81/U UNDERFREQUENCY

Secondary Supply to Relays

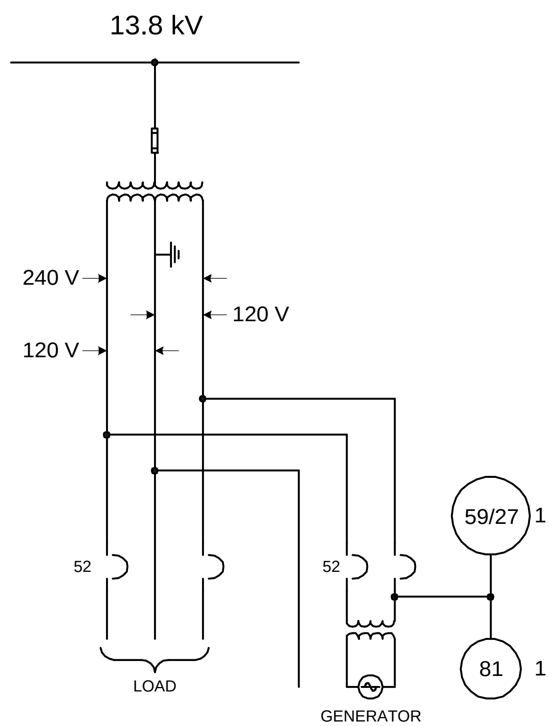
FIGURE 2



27 UNDERVOLTAGE
50 INSTANTANEOUS OVERCURRENT-PHASE
50N INSTANTANEOUS OVERCURRENT-GROUND
51 TIME DELAY OVERCURRENT-PHASE
51N TIME DELAY OVERCURRENT-GROUND
52 CIRCUIT BREAKER
59 OVERVOLTAGE
81/O OVERFREQUENCY
81/U UNDERFREQUENCY

Secondary Supply to Relays
Separate Generator Circuit Breaker

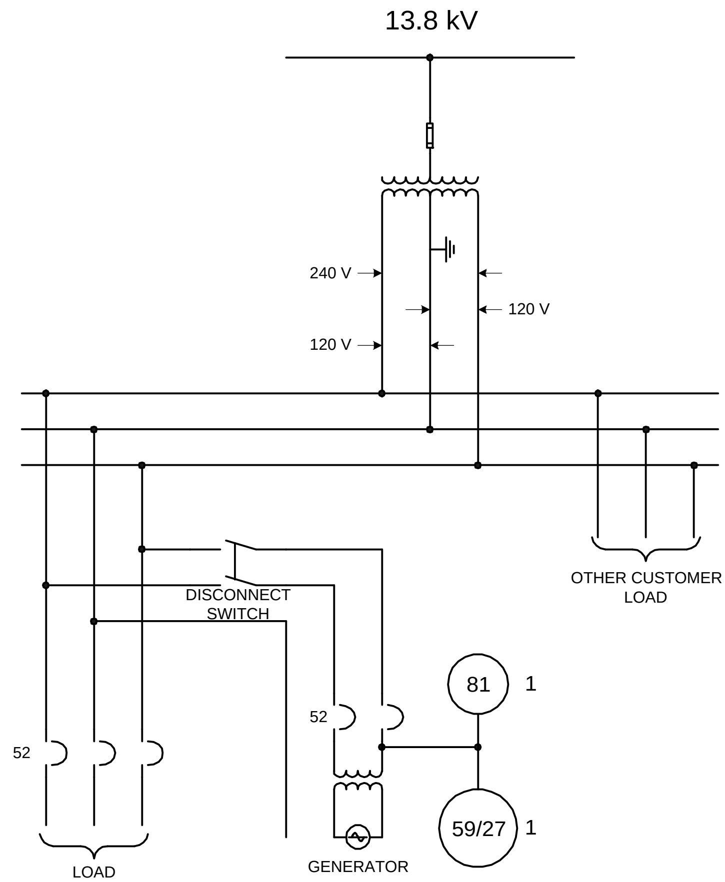
FIGURE 3



52 MOLDED CASE BREAKER
59/27 OVER/UNDER VOLTAGE
81 FREQUENCY

Relaying for Single-Phase Source -
Induction Generator or Line Commutated Inverter
with a Dedicated Transformer

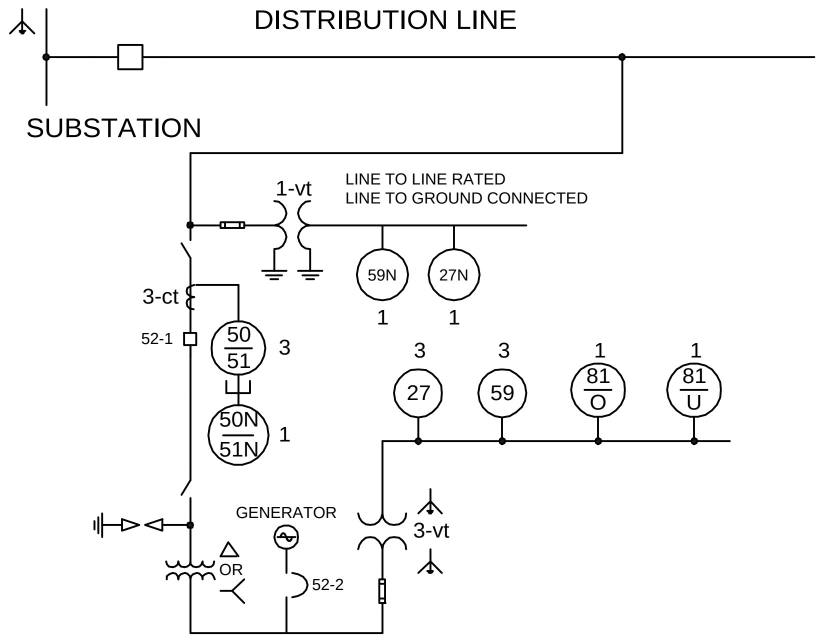
FIGURE 4



52 MOLDED CASE BREAKER
59/27 OVER/UNDER VOLTAGE
81 FREQUENCY

Relaying for Single-Phase Source
Induction Generator or Line Commutated Inverter
Connected to the Secondary Service

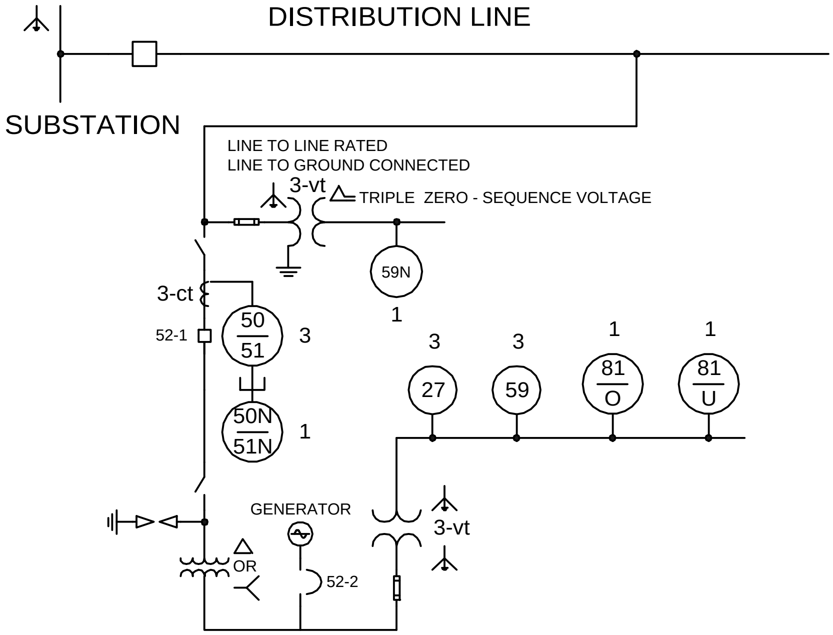
FIGURE 5



27 UNDERVOLTAGE
27N UNDERVOLTAGE-GROUND
50 INSTANTANEOUS OVERCURRENT-PHASE
50N INSTANTANEOUS OVERCURRENT-GROUND
51 TIME DELAY OVERCURRENT-PHASE
51N TIME DELAY OVERCURRENT-GROUND
52 CIRCUIT BREAKER
59 OVERVOLTAGE
59N OVERVOLTAGE-GROUND
81/O OVERFREQUENCY
81/U UNDERFREQUENCY

Ungrounded Primary Relayed by Undervoltage/Overvoltage

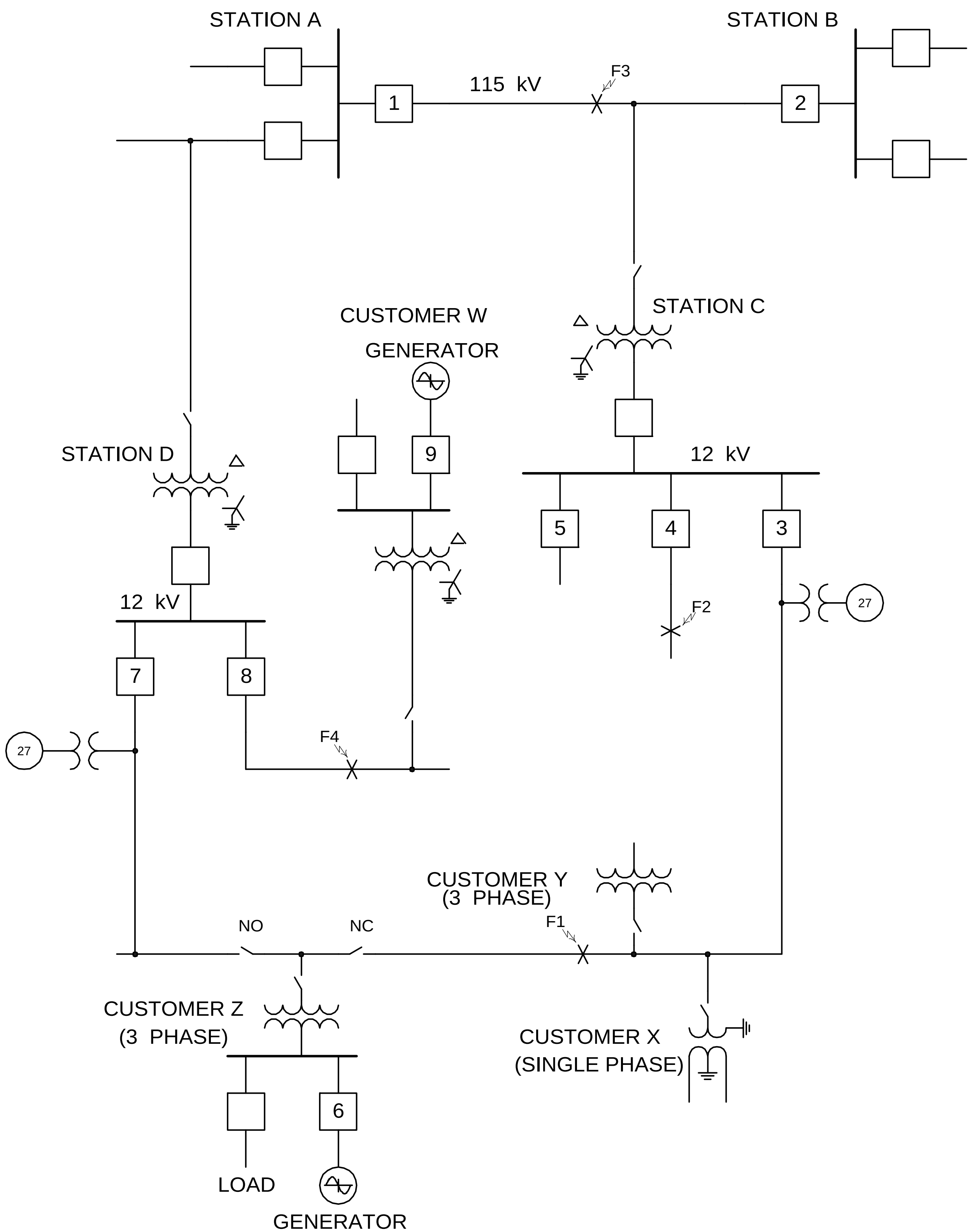
FIGURE 6



27 UNDERVOLTAGE
50 INSTANTANEOUS OVERCURRENT-PHASE
50N INSTANTANEOUS OVERCURRENT-RESIDUAL
51 TIME DELAY OVERCURRENT-PHASE
51N TIME DELAY OVERCURRENT-RESIDUAL
52 CIRCUIT BREAKER
59 OVERVOLTAGE
59N OVERVOLTAGE-ZERO SEQUENCE
81/O OVERFREQUENCY
81/U UNDERFREQUENCY

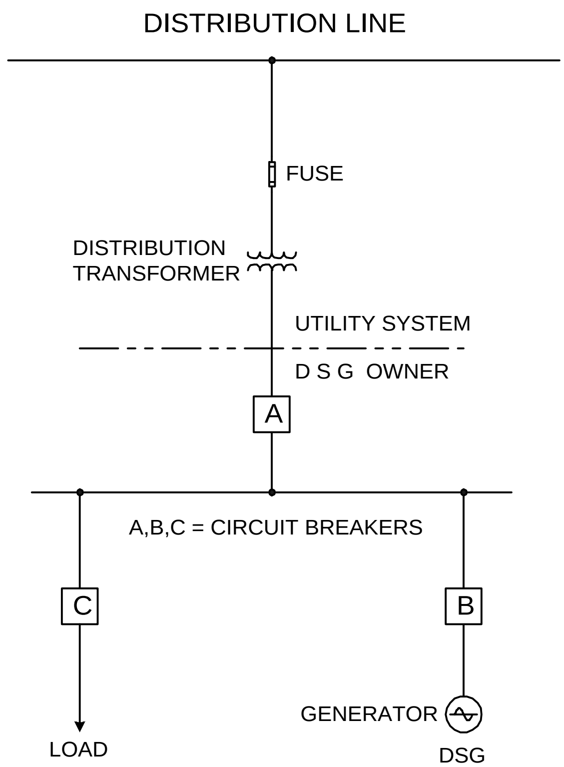
Ungrounded Primary
Relayed by Triple Zero Sequence Voltage

FIGURE 7



Examples of Faults

FIGURE 8



Switching Device Location

FIGURE 9