Generator Protection Application Guide

Purpose

This guide was developed to assist in the selection of relays and relay systems to protect a generator.

About Basler

Basler Electric is a manufacturer of excitation systems, voltage regulators, genset controls, protective relays, custom transformers, and injection molded plastic components. Basler also offers turnkey engineering services through their Basler Services, LLC subsidiary.

Basler products control and manage the delivery of electricity and are commonly found in applications such as power plants, substations, hydro dams, agricultural facilities, airports, refineries, telecom facilities, factories, marine applications, and many others.

Basler has been in business since 1942 and our products are in operation in over 145 countries around the world.

Notice

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1. Introduction

This guide was developed to assist in the selection of relays and relay systems to protect a generator. The purpose of each protective element is described and related to one or more power system configurations. A large number of relays and relay systems is available to protect for a wide variety of conditions. These provide protection to the generator or prime mover from damage. They also protect the external power system or the processes it supplies. The basic principles offered here apply equally to individual relays and to multifunction digital packages. An example of the typical configuration settings for a 2MW diesel genset using the Basler BE1-FLEX Protection, Automation and Control System is included near the end of this guide.

The engineer must balance the expenseof applying a particular relay or relay system against the consequences of losing a generator.The total loss of a generator may not be catastrophic if it represents a small percentage of the investment in an installation. However, the impact on service reliability and upset to loads supplied must be considered. Damage to and loss of product in continuous processescan represent the dominating concern rather than the generator unit. Accordingly, there is no standard solution based on the MW rating. However, it is rather expected that a 500 kW, 480 V, standby-reciprocating engine will have less protection than a 400 MW base load steamturbine unit will. One possible common dividing point is that the extra CTs needed for current differential protection are less commonly seen on generators less than 2 MVA, generators rated less than 600 V and generators that are never paralleled to other generation.

This guide simplifies the process of selecting relays by describing how to protect against each type of external and internal fault or abnormal condition. Then, suggestions are made for what is considered minimum protection as a baseline. After establishing the baseline, additional protection, as described in the section on Integrated Application Examples, may be added.

The subjects covered in this guide are as follows:

- Ground Fault (50/51-G/N, 27/59, 59N, 27-3N, 87N)
- Phase Fault (51, 51V, 87)
- Backup Remote Fault Detection (51V, 21)
- Reverse Power (32)
- Loss of Field (40Q and 40Z)
- Thermal (49RTD)
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- Integrated Application Examples
- Application of BE1-FLEX Protection, Automation and Control System
- Typical Settings
- Basler Electric Products for Protection

The references listed at the end of this guide provide more background on this subject. These documents also contain Bibliographies for further study.

2. Ground Fault Protection

The following information and examples cover three impedance levels of grounding: low-, medium- and high-impedance grounding. A low-impedance grounded generator is a generator that has zero or minimal impedance applied at the wye neutral point so that, during a ground fault at the generator HV terminals, ground current from the generator is approximately equal to three-phase fault current. A medium-impedance grounded generator is a generator that has substantial impedance applied at the wye neutral point so that, during a ground fault, a reduced but readily detectable level of ground current, typically

100-500 A, flows. A high-impedance grounded generator is a generator with a large grounding impedance so that, during a ground fault, a nearly undetectable level of fault current flows, making ground fault monitoring with voltage- based (e.g., third-harmonic voltage monitoring and fundamental frequency neutral-voltage-shift monitoring) protection necessary. The location of the grounding, generator neutral(s) or transformer also influences the protection approach.

The location of the ground fault within the generator winding, as well as the grounding impedance, determines the level of fault current. Assuming that the generated voltage along each segment of the winding is uniform, the prefault line-ground voltage level is proportional to the percent of winding between the fault location and the generator neutral, V_{FG} in Figure 1. Assuming an impedance grounded generator where ($Z_{0,\,SOURCE}$ and Z_N)>>$Z_{WINDING}$, the current level is directly proportional to the distance of the point from the generator neutral [Figure 1(a)], so a fault 10% from neutral produces 10% of the current that flows for a fault on the generator terminals. While the current level drops towards zero as the neutral is approached, the insulation stress also drops, reducing the probability of a damaging fault near the neutral. If a generator grounding impedance is low relative to the generator winding impedance or the system ground impedance is low, the fault current decay will be non-linear. For I1 in Figure 1, lower fault voltage is offset by lower generator winding resistance. An example is shown in Figure 1(b).

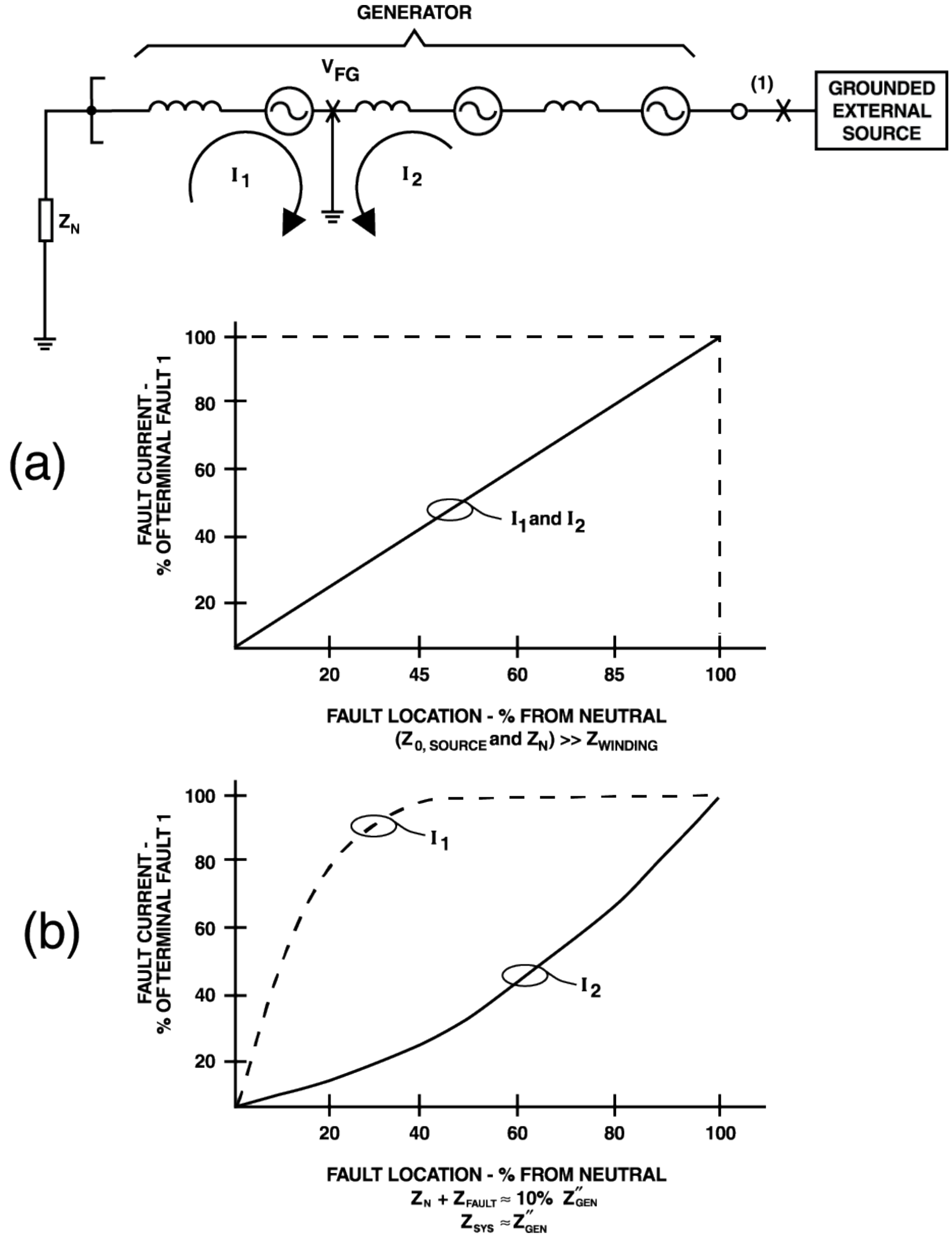


Figure 1. Effects of Fault Location within Generator on Current Level

The generator differential function (87) might be sufficiently sensitive to detect winding ground faults with low-impedance grounding per Figure 2. This would be the case if a solid generator-terminal fault produces approximately 100% of rated current. The minimum pickup setting of the differential function (e.g., Basler BE1-FLEX, see Table 2) should be adjusted to sense faults on as much of the winding as possible. However, settings below 10% of full load current (e.g., 0.4 A for 4 A full load current) carry increased risk of misoperation because of transient CT saturation during external faults or during step-up transformer energization. Lower pickup settings are recommended only with high-quality CTs (e.g., C400) and a good CT match (e.g., identical accuracy class and equal burdens).

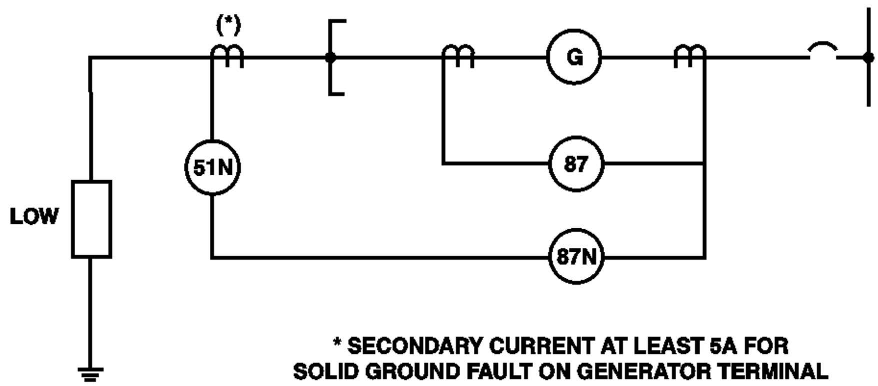


Figure 2. Ground-Fault Protection – Generator Low-Impedance Grounding

If 87 protection is provided per Figure 2, a 51N function (e.g., Basler relays per Table 2) backs up the 87, as well as external relays. If an 87 is not provided or is not sufficiently sensitive for ground faults, then the 87N provides the primary protection for the generator and the 51N backup. The advantage of the 87 and 87N is they do not need to be delayed to coordinate with external protection; however, delay is required for the 51N. One must be aware of the effects of transient dc offset induced saturation on CTs during transformer or load energization with respect to the high-speed operation of 87 relays. Transient dc offset can induce CT saturation for many cycles (likely not more than 10 cycles), which may cause false operation of an 87 function and relay systems. This may be addressed by the following:

- Not block loading the generator
- Avoiding sudden energization of large transformers
- Providing substantially overrated CTs
- Adding a very small time delay to the 87 trip circuit
- Reducing sensitivity of 87 setting

The neutral CT should be selected to produce a secondary current of at least 5 A for a solid generator terminal fault, providing sufficient current for a fault near the generator neutral. For example, if a terminal fault produces 1000 A in the generator neutral, the neutral CT ratio should not exceed 1000/5. For a fault 10% from the neutral and assuming I1 is proportional to percent winding from the neutral, the 51N current will be 0.5 A, with a 1000/5 CT.

Figure 3 shows multiple generators with the transformer providing the system grounding. This arrangement applies if the generators will not be operated with the transformer out of service. The scheme will lack ground fault protection before generator breakers are closed. The transformer could serve a step-up as well as a grounding transformer function. An overcurrent function 51N or a differential function 87 provides the protection for each generator. The transformer should produce a ground current of at least 50% of generator rated current to provide about 95% or more winding coverage.

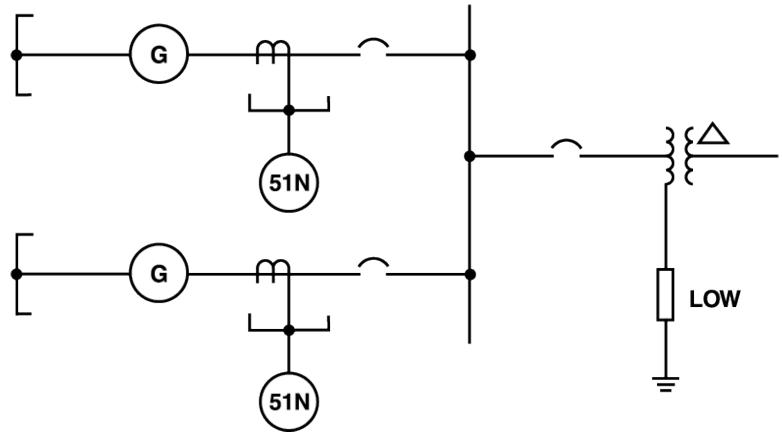


Figure 3. System Grounded Externally with Multiple Generators

Figure 4 shows a unit-connected arrangement (generator and step-up transformer directly connected with no low-side breaker), using high-impedance grounding. The grounding resistor and voltage elements are connected to the secondary of a distribution transformer. The resistance is normally selected so that the reflected primary resistance is approximately equal to one third of the single-phase line-to- ground capacitive reactance of the generator, bus, and step-up transformer. This will limit fault current to 5-10 A primary. Sufficient resistor damping prevents ratcheting up of the unfaulted phase voltages in the presence of an intermittent ground. The low current level minimizes the possibility of sufficient iron damage to require restacking. Because of the low current level, the 87 will not operate for single-phase ground faults.

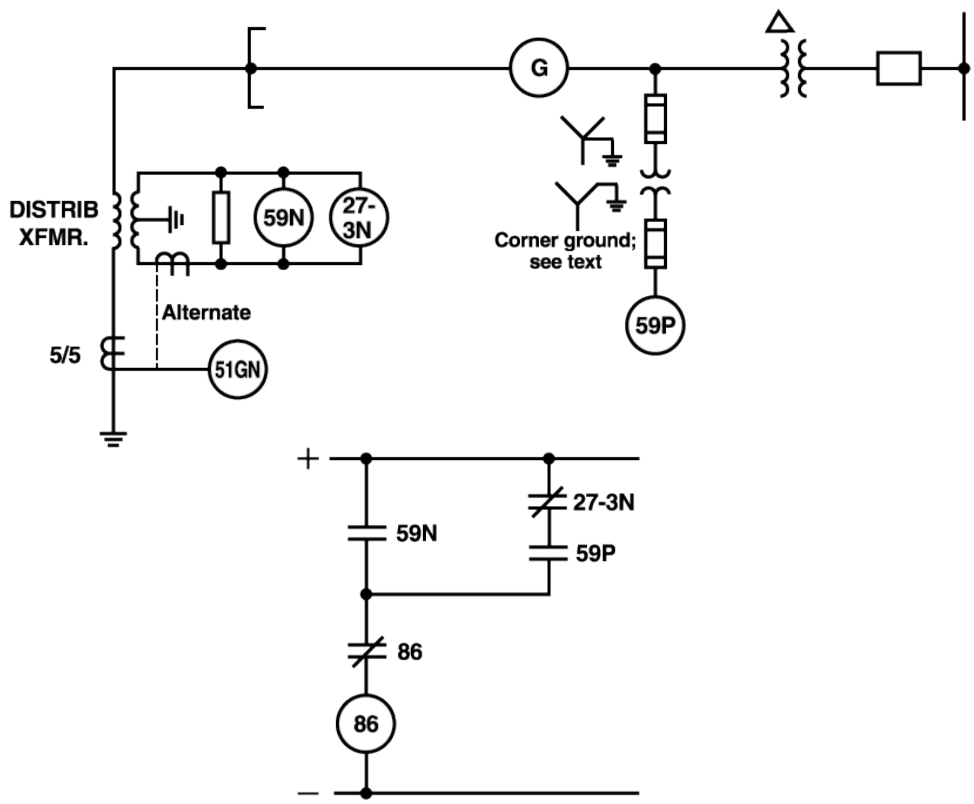


Figure 4. Unit-Connected Case with High-Impedance Grounding

Protection in Figure 4 consists of a 59N overvoltage element and a 27-3N third-harmonic undervoltage element (see Table 2). As shown in Figure 5, a ground fault at the generator high-voltage bushings elevates the un-faulted phase line–to-ground voltages to a nominal 173% of normal line to neutral voltages. In addition, the neutral-to-ground voltage will rise to normal phase-ground voltage levels. The closer the ground fault is to the generator neutral, the less the neutral-to-ground voltage will be. One method to sense this neutral shift is with the 59N protection (Figure 4) monitoring the generator neutral. The 59N will sense and protect the generator for ground faults over about 95% of the generator winding.

The 59N (see Table 2) element should be selected to not respond to third-harmonic voltage produced during normal operation. The 59N will not operate for faults near the generator neutral because of the reduced neutral shift during this type of fault.

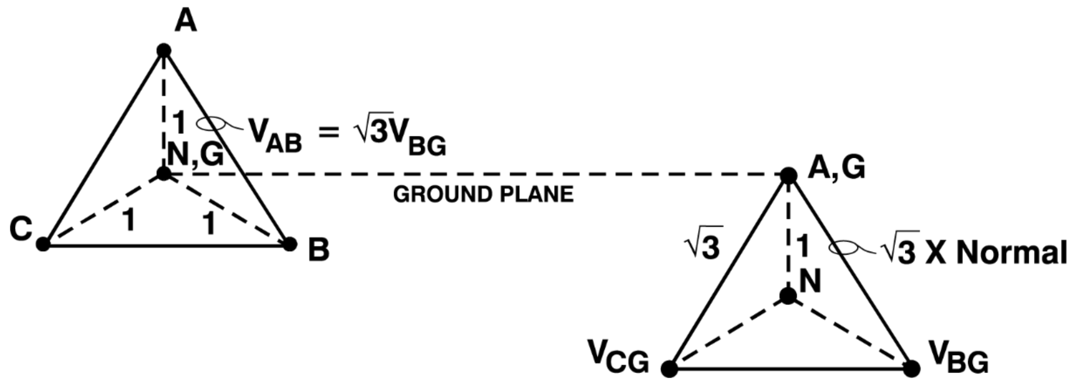


Figure 5. Neutral Shift during Ground Fault on High Impedance Grounded System

Faults near the generator neutral can be sensed with the 27-3N. When high-impedance grounding is in use, a detectable level of third- harmonic voltage usually exists at the generator neutral, typically 1–5% of generator line-to-neutral fundamental voltage. The level of third harmonic depends on generator design and can be very low in some generators. A 2/3 pitch machine will experience a notably reduced third-harmonic voltage. The level of harmonic voltage will likely decrease at lower excitation levels and lower load levels. During ground faults near the generator neutral, the third-harmonic voltage in the generator neutral is shorted to ground, causing the 27-3N to drop out (Figure 6). It is important that the 27-3N have high rejection of fundamental frequency voltage.

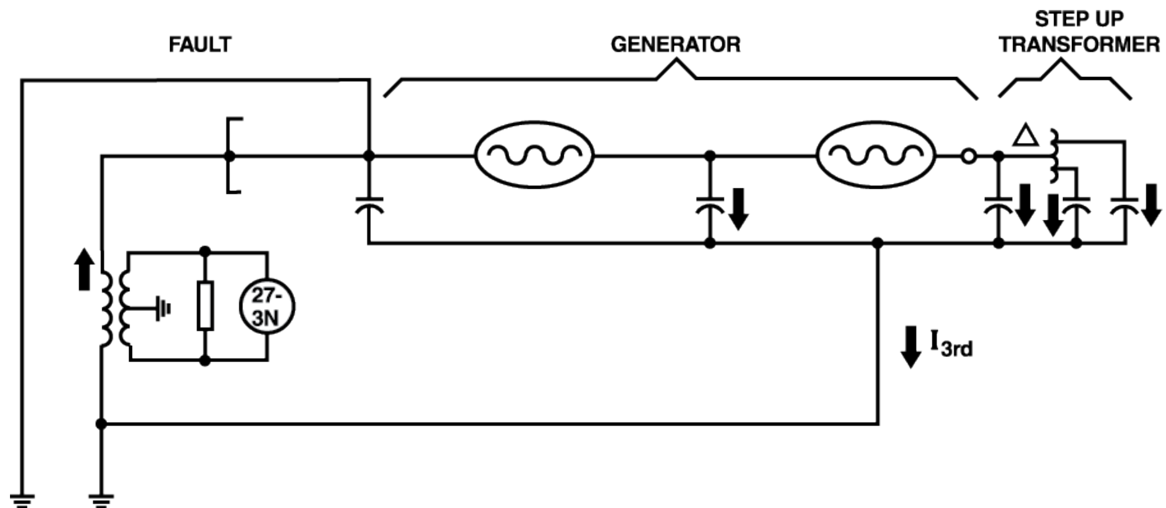


Figure 6. Ground Fault near Generator Neutral Reduces
Third-Harmonic Voltage in Generator Neutral, Dropping Out 27-3N

The 27-3N performs a valuable monitoring function aside from its fault detection function; if the grounding system is shorted or opens, the 27-3N drops out.

The 59P phase overvoltage element in Figure 4 supervises the 27-3N so the 86 lockout element can be reset when the generator is out of service; otherwise, the field could not be applied. Once the field is applied and the 59P operates, the 27-3N protection is enabled. The 59P element should be set for about 90% of rated voltage. An “a” contact of the unit breaker can be used instead of the 59P protection to supervise 27-3N tripping. Blocking the 27-3N until some level of forward power exists has also been done. However, the use of a 59P element allows the 27-3N to provide protection prior to synchronization (i.e., putting the unit online), once the field has been applied.

To provide 100% stator winding coverage in high-impedance grounded generators, the undervoltage (27-3N) and overvoltage (59N) settings should overlap. For example, if a generator-terminal fault produces 240 V, 60 Hz across the neutral voltage element (59N), a 1V pickup setting (a fairly sensitive setting) would allow all but the last (1/240) • 100 = 0.416% of the winding to be covered by the overvoltage function. If 20V third harmonic is developed across the relay prior to a fault, a 1 V third-harmonic dropout setting would provide dropout for a fault to (1/20) • 100 = 5% from the neutral. Setting the 59N pickup too low or the 27-3N dropout too low might result in operation of the ground detection system during normal operating conditions. The third-harmonic dropout level can be the hardest to properly set, because this level depends on machine design, generator excitation and load levels. It is advisable to measure third-harmonic voltages at the generator neutral during unloaded and loaded conditions prior to selecting a setting for the 27-3N dropout. In some generators, the third harmonic at the neutral can become almost unmeasurably low during low excitation and low load levels, requiring blocking the 27-3N tripping mode with a supervising 32 underpower element when the generator is running unloaded.

There is also some level of third-harmonic voltage present at the generator high voltage terminals. A somewhat predictable ratio of ($V_{3RD\text{-}GEN.HV.TERM}$)/($V_{3RD\text{-}GEN.NEUTRAL}$) will exist under all load conditions, though this ratio can change if loading induces changes in third-harmonic voltages. A ground fault at the generator neutral will change this ratio, providing another means to detect a generator ground fault. Two difficulties with this method are these: problems with developing a way to accurately sense low third-harmonic voltages at the generator high-voltage terminals in the presence of large fundamental-frequency voltages and problems with dealing with the changes in the third-harmonic ratio under some operating conditions.

If the 59N protection is used only for alarming, the distribution transformer voltage ratio should be selected to limit the secondary voltage to the maximum continuous rating of the relay. If the relay is used for tripping, the secondary voltage could be as high as the relay's ten-second voltage rating. Tripping is recommended to minimize iron damage for a winding fault as well as minimizing the possibility of a multi-phase fault.

Where wye-wye voltage transformers (VTs) are connected to the machine terminals, the secondary VT neutral should not be grounded to avoid operation of the 59N protection for a secondary ground fault. Instead, one of the phase leads should be grounded (i.e., "corner ground"), leaving the neutral to float. This connection eliminates any voltage across the 59N element for a secondary phase-to-ground fault. If the VT secondary neutral is grounded, a phase-ground VT secondary fault pulls little current, so the secondary fuse sees little current and does not operate. The fault appears to be a high impedance phase-to-ground fault as seen by the generator neutral-shift sensing protection (59N), leading to a generator trip. Alternatively, assume that the VT corner (e.g., phase A) has been grounded. If phase B or C faults to ground, then the fault will appear as a phase-to-phase fault, which will pull high secondary currents and will clear the secondary fuse rapidly and prevent 59N operation. A neutral-to-ground fault tends to operate the 59N, but this is a low likelihood event. An isolation VT is required if the generator VTs would otherwise be galvanically connected to a set of neutral-grounded VTs. Three wye VTs should be applied where an iso-phase bus (phase conductors separately enclosed) is used to protect against phase-to-phase faults on the generator terminals.

The 59N element in Figure 4 is subject to operation for a ground fault on the wye side of any power transformer connected to the generator. This voltage is developed even though the generator connects to a delta winding because of the transformer inter-winding capacitance. This coupling is so small that its effect can ordinarily be ignored; however, this is not the case with the 59N application because of the very high grounding resistance. The 59N overvoltage element time delay allows the relay to override external-fault clearing.

The Basler BE1-FLEX relay with voltage inputs features the required neutral overvoltage (59N), undervoltage (27-3N) and phase overvoltage (59P) units.

Figure 4 also shows a 51GN element as a second way to detect a stator ground fault. The use of a 51GN in addition to the 59N and 27-3N is readily justified because the most likely fault is a stator ground fault. An undetected stator ground fault would be catastrophic, eventually resulting in a multi-phase fault with high current flow, which persists until the field flux decays (e.g., for 1–4s). The CT shown in Figure 4 could be replaced with a CT in the secondary of the distribution transformer, allowing use of a CT with a lower voltage rating. However, the 51GN element would then be inoperative if the distribution transformer primary becomes shorted. The CT ratio for the secondary-connected configuration should provide for a relay current about equal to the generator neutral current (i.e., 5:5 CT). In either position, the relay pickup should be above the harmonic current flow during normal operation. (Typically, harmonic current will be less than 1A but the relay can be set lower if the relay filters harmonic currents and responds only to fundamental currents.) Assuming a maximum fault current of 8 A primary in the neutral and a relay set to pick up at 1 A primary, 88% of the stator winding is covered. As with the 59N element, the 51GN delay will allow it to override clearing of a high-side ground fault. An instantaneous overcurrent element can also be employed, set at about three times the time overcurrent element pickup; although it might not coordinate with primary VT fuses that are connected to the generator terminals.

Multiple generators, per Figure 7, can be high-impedance grounded, but 59N protection will not be selective. A ground fault anywhere on the generation bus or on the separate generators will be seen by all 59N elements, and the tendency will be for all generators to trip. The 51N relay, when connected to a flux summation CT, will provide selective tripping if at least three generators are in service. In this case, the faulted generator 51N protection will then see more current than the other 51N elements. The proper 51N will operate before the others because of the inverse characteristic of the relays. Use of the flux summation CT is limited to those cases where the CT window can accommodate the three cables. Fault currents are relatively low, so care must be exercised in selecting an appropriate nominal relay current level (e.g., 5 A vs. 1 A) and CT ratio. For example, with a 30 A fault level and a 50 to 5 A CT, a 1 A nominal 51N with a pickup of 0.1 A might be used. With two generators, each contributing 10 A to a terminal fault in a third generator, the faulted-generator 51N function sees 2•10/(50/5) = 2 A. Then the relay protects down to ([0.1]/2) • 100 = 5% from the neutral.

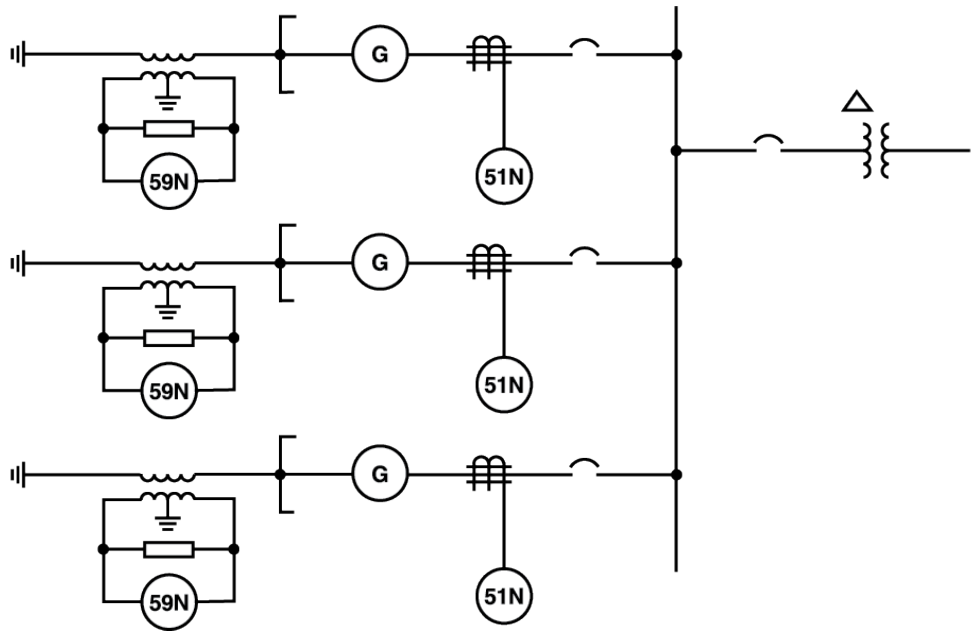


Figure 7. 59N Protection Operation with Multiple Units will not be Selective;
51N Protection Provides Selective Protection if at least Three Generators are in Service

When feeder cables are connected to the generator bus, the additional capacitance dictates a much lower level of grounding resistance than achieved with a unit-connected case. A lower resistance is required to minimize transient overvoltages during an arcing fault.

The BE1-FLEX neutral differential (87N), neutral directional (67N), or neutral overcurrent (51N) can be used to detect ground faults in solidly or low-impedance grounded generators as shown in Figure 8. The 51N is typically set to 10% of available ground fault current and must be coordinated with other system ground fault protections. The 67N complements the operation of the 51N, and is set to trip for ground fault current flowing toward the generator and has a shorter time delay. The 87N element detects the difference current between the calculated neutral current (3I0) and the measured ground current (IG). The 87N is more commonly found on generators that already have CTs required for phase differential relaying. The 87N will typically operate for ground faults as low as 50% of the phase fault current in these applications. Whichever approach is used, an effort should be made to select relay settings to trip for faults as low as 10% of maximum ground fault current levels. During external phase faults, considerable 87N operating current can occur when there is dissimilar saturation of the phase CTs caused by high ac current or transient dc offset effects, while the generator neutral current is still zero, assuming balanced conductor impedances to the fault. The transient monitor feature of the BE1-FLEX, 87N, has an adjustable time delay setting to ride through possible transient CT saturation caused by these high fault current, two-phase-to-ground external faults.

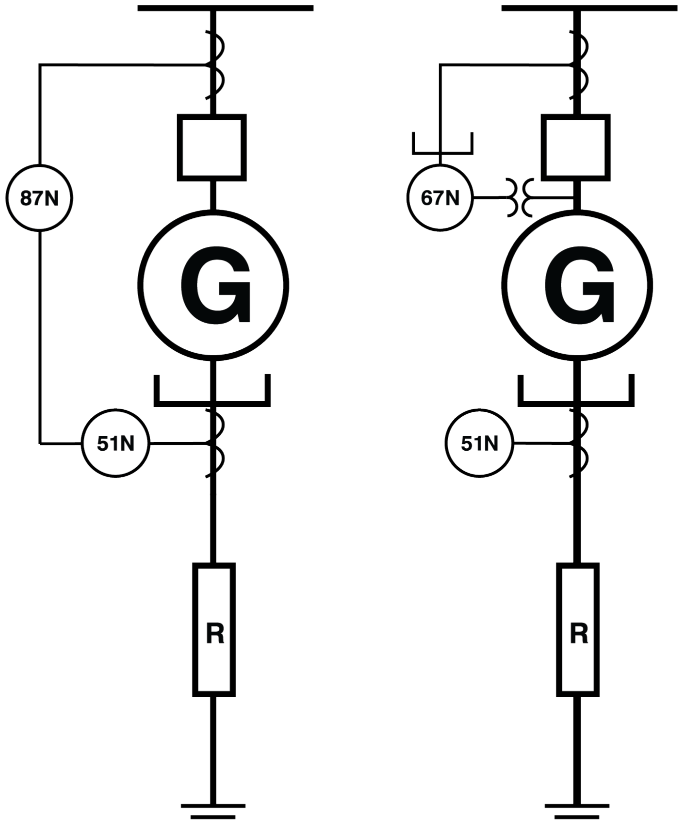


Figure 8. Ground Fault Protection with 87N, 67N, and 51N

3. Phase-Fault Protection

Fig. 9 shows a simple method of detecting phase faults, but clearing is delayed, because the 51 function must be delayed to coordinate with external devices. Because the 51 function operates for external faults, it is not generator-zone selective. It will operate for abnormal external operating conditions such as remote faults that are not properly cleared by remote breakers. The 51 pickup should be set at about 175% of rated current to override swings because of a slow-clearing external fault, the starting of a large motor or the reacceleration current of a group of motors. Energization of a transformer might also subject the generator to higher-than-rated current flow.

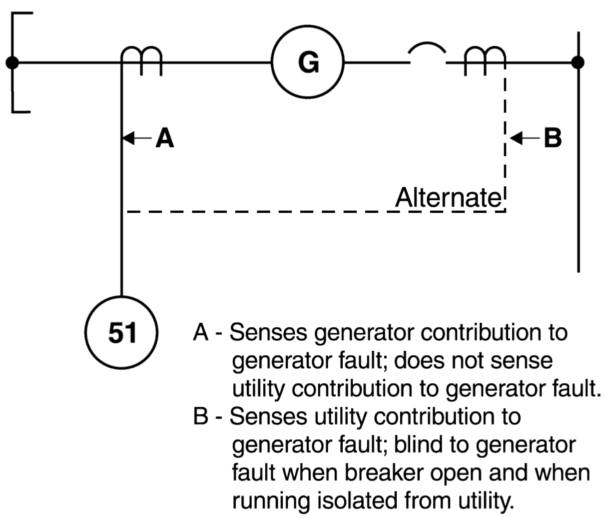


Figure 9. Phase Overcurrent Protection (51) must be delayed to coordinate with External Relays

Figure 10 shows an example of generator current decays for a three-phase fault and a phase-to-phase fault. For a three-phase fault, the fault current decays below the pickup level of the 51 element in approximately one second. If the delay of the 51 can be selectively set to operate before the current drops to pickup, the relay will provide three-phase fault protection. The current does not decay as fast for a phase-to-phase or a phase-to-ground fault and, thereby, allows the 51 function more time to trip before current drops below pickup. Figure 10 assumes no voltage regulator boosting, although the excitation system response time is unlikely to provide significant fault current boosting in the first second of the fault. It also assumes no voltage regulator dropout because of loss of excitation power during the fault. If the generator is loaded prior to the fault, pre-fault load current and the associated higher excitation levels will provide the fault with a higher level of current than indicated by the Figure 10 curves. An estimate of the net fault current of a pre-loaded generator is a superposition of load current and fault current without pre-loading. For example, assuming a pre-fault 1 pu rated load at 30 degree lag, at one second the three-phase fault value would be 2.4 times rated, rather than 1.75 times rated (1@30° + 1.75@90° = 2.4@69°). Under these circumstances, the 51 function has more time to operate before current decays below pickup.

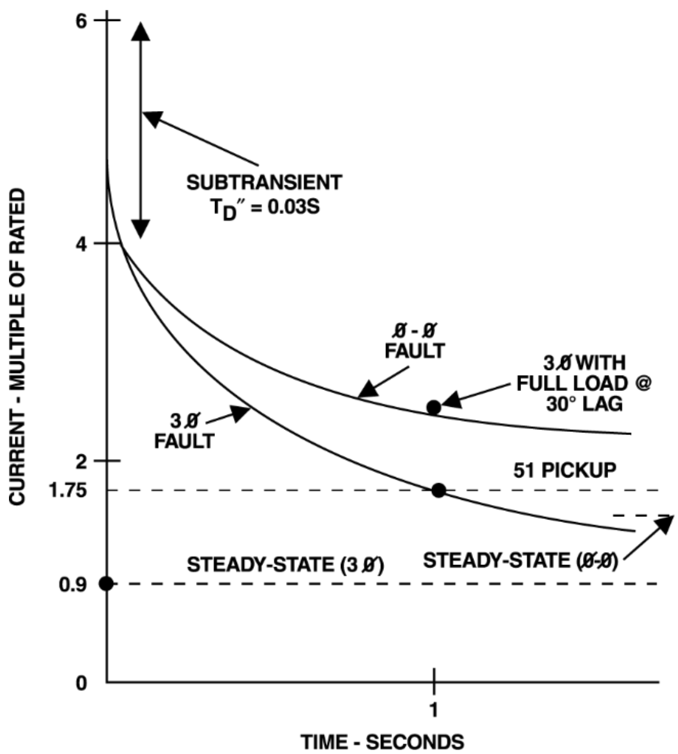


Figure 10. Generator Fault Current Decay Example for Three-Phase and Phase-Phase Faults at Generator Terminals – with No Regulator Boosting or Dropout during Fault and No Prefault Load

Figure 9 shows the CTs on the neutral side of the generator. This location allows the relay to sense internal generator faults but does not sense fault current entering the generator from the external system. Placing the CT on the system side of the generator introduces a problem of the relay not seeing a generator internal fault when the main breaker is open and when running the generator isolated from other generation or the utility. If an external source contributes more current than does the generator, using CTs on the generator terminals, rather than neutral-side CTs, will increase 51 protection sensitivity to internal faults because of higher current contribution from the external source; however, the generator is unprotected should a fault occur with the breaker open or prior to synchronizing.

Voltage-restrained or voltage-controlled time-overcurrent elements (51VR, 51VC) can be used as shown in Figure 11 to remove any concerns about the ability to operate before the generator current drops too low. The voltage feature allows the relays to be set below rated current. The Basler BE1-FLEX relay causes the pickup to decrease with decreasing voltage. For example, the relay might be set for about 175% of generator rated current with rated voltage applied; at 25% voltage the relay picks up at 25% of the relay setting (1.75 • 0.25 = 0.44 times rated).

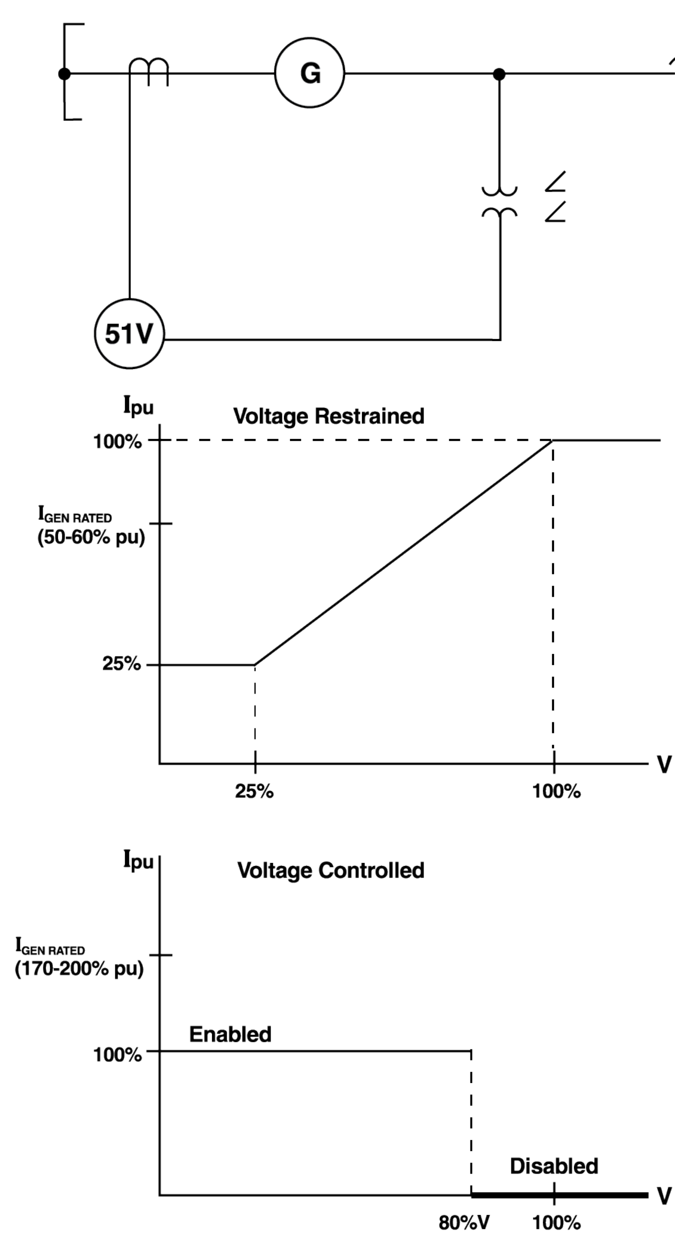


Figure 11. Voltage-Restrained or Voltage-Controlled Time Overcurrent Phase Fault Protection

The Basler BE1-FLEX relay inhibits operation of the overcurrent element until the voltage drops below a preset voltage. It should be set to function below about 80% of rated voltage with a current pickup of about 50% of generator rated. Because the voltage-controlled type has a fixed pickup, it can be more readily coordinated with external relays than can the voltage-restrained type. The voltage-controlled type is recommended because it is easier to coordinate. However, the voltage-restrained type will be less susceptible to operation on swings or motor starting conditions that depress the voltage below the voltage-controlled undervoltage unit dropout point.

Figure 12 eliminates concerns about the decay rate of the generator current by using an instantaneous overcurrent protection (50) on a flux summation CT, where the CT window can accommodate cable from both sides of the generator. The relay does not respond to generator load current nor to external fault conditions. The instantaneous overcurrent relay (50) acts as a phase differential function (87) and provides high-speed sensitive protection. This approach allows for high sensitivity. For instance, it would be feasible to sense fault currents as low as 1-5% of generator full-load current. It is common to use 50/5 CTs and to use 1 A nominal relaying. A low CT ratio introduces critical saturation concerns (e.g., a 5,000 A primary fault might attempt to drive a 500 A secondary current on a 50/5 CT). The CT burden must be low to prevent saturation of the CT during internal faults that tend to highly overdrive the CT secondary.

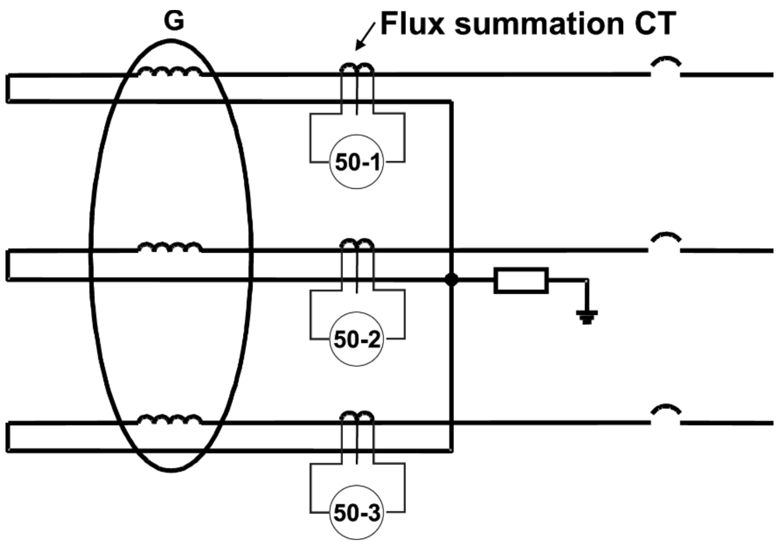


Figure 12. Flux Summation Protection (50) Provides Sensitive, High-Speed, Selective Differential Protection (87)

The 87 function of the BE1-FLEX relay in Figure 13 is connected to respond to phase differential currents from two sets of CTs. In some applications, it might include a unit differential that includes the step-up transformer. In contrast to a 51 or 51V function that monitors only one CT, the 87 element responds to both the generator and external contributions to a generator fault. Because of the differential connection, the relay is immune, except for transient CT saturation effects, to operation because of generator load flow or external faults and, therefore, can provide sensitive, high-speed protection. These CTs do not need to be matched in performance, but the minimum pickup of the 87 element must be raised as the degree of performance mismatch increases. See the BE1-FLEX instruction manual for specifics on settings. A pickup of 0.4 A for the 87 element is representative of a recommended setting for a moderate mismatch in CT quality and burden. Figure 13 also shows 51V elements to back up the 87 and external relays and breakers.

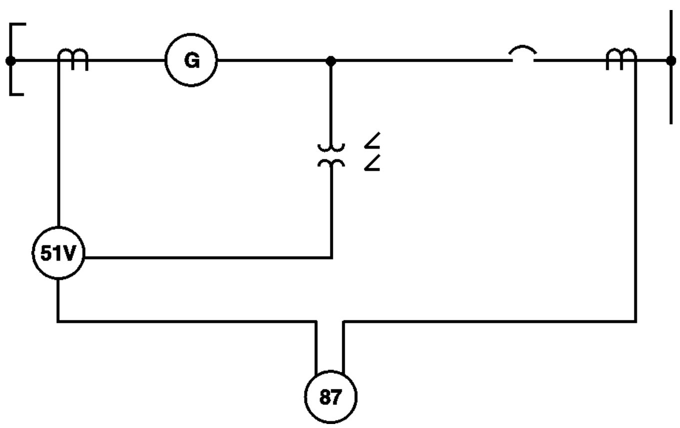


Figure 13. 87 Provides Sensitive, High-Speed Coverage, 51V Provides Backup for 87 and for External Relays

The BE1-FLEX is recommended for overall differential protection that includes a step-up transformer, generator breaker, and other associated equipment. See Figure 14. A single BE1-FLEX with a BE1-64F for field ground can protect this full system. Protection can be sectionalized into more BE1-FLEX and redundant devices can be utilized based upon specific application requirements.

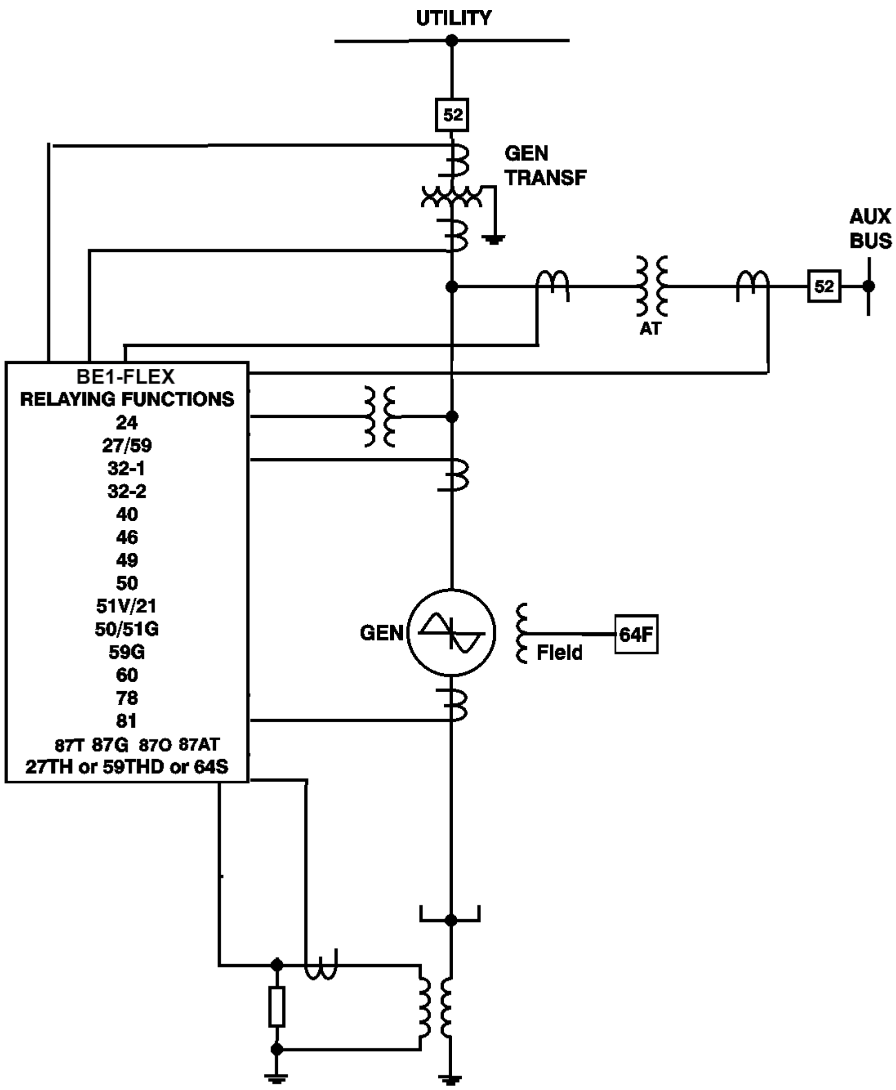


Figure 14. Typical Protection for a Large Generator (Includes Overall Differential Zone 87O)

As the 87 does not detect turn-to-turn faults, the split-phase relaying scheme can be used to detect this condition. This scheme requires the stator windings to be split into two equal groups and the currents of each group are compared (Figure 15). The scheme typically utilizes a time- overcurrent (51) or instantaneous overcurrent (50) function for each phase to detect the unbalance current. The relays should generally be set above any normal unbalanced current but below the unbalanced current caused by a single-turn fault. The minimum pickup of the time overcurrent (51) element should be at 1.5 times the maximum split-phase current. The time delay should be set to prevent operation on CT transient error currents during external faults. The instantaneous (50) pickup should be set approximately at seven times the minimum pickup of the time overcurrent (51). Figure 15 shows the split-phase relaying scheme.

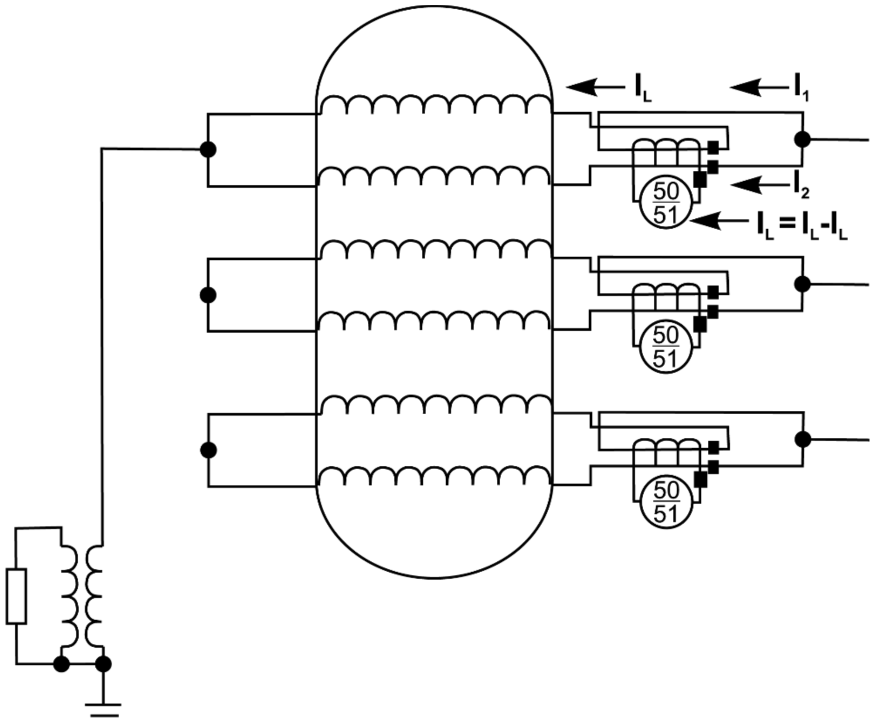


Figure 15. Split-Phase Relaying Scheme using Single Window CTs (Reference IEEE Std. C37.102-2006)

In instances where stator-winding configurations do not allow the application of split-phase protection, a neutral overvoltage (59N) can be used to detect a turn-to-turn fault by using three VTs connected in wye on the primary side and the primary ground lead tied to the generator neutral. The secondary is connected in broken delta with an overvoltage function connected across the open end to measure $3V_0$ as shown in Figure 16.

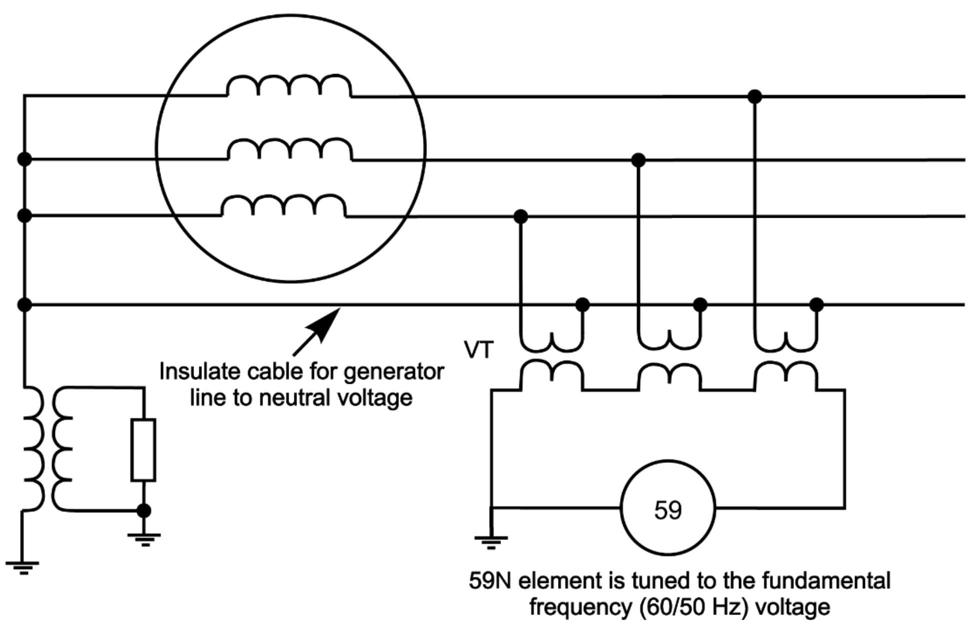


Figure 16. Turn-to-Turn Fault Protection using a BE1-FLEX

With the primary ground lead tied to the generator neutral, the 59N is insensitive to stator ground faults but will operate for turn-to-turn faults that increase the $3V_0$ voltage above low normal levels. The 59N is tuned to fundamental frequency (60Hz) voltage. The cable from the neutral of the VT to the generator neutral must be insulated for the system line-to-ground voltage.

The Basler BE1-FLEX relay can be used for this protection by utilizing the overvoltage (59) element.

Another way to detect external faults is with impedance relaying (21). Impedance relaying divides voltage by current on a complex number plane (Z = V/I using phasor math) (Figures 17 and 18). Such relaying is inherently faster than time-overcurrent relaying. In the most common format of impedance relaying, the tripping zone is the area covered by a "mho" circle on the R-X plane that has a diameter from the origin (the CT, VT location) to some remote set point on the R-X plane. If the fault impedance is within the zone, the relay will trip. Multiple zones can be used, with delays on all zones as appropriate for coordinating with line relays. Impedance relaying is highly directional. In Figure 17, however, because the CT is on the neutral rather than at the VT, the relay will see faults in both the generator and in the remote system. The Basler BE1-FLEX is equipped with this protection. Refer to IEEE Standard 37.102 for settings information and a setting example.

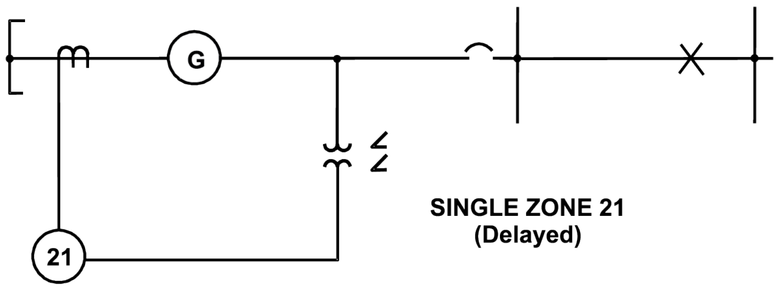


Figure 17. Impedance Relay, Looking for Generator and Remote Line Faults

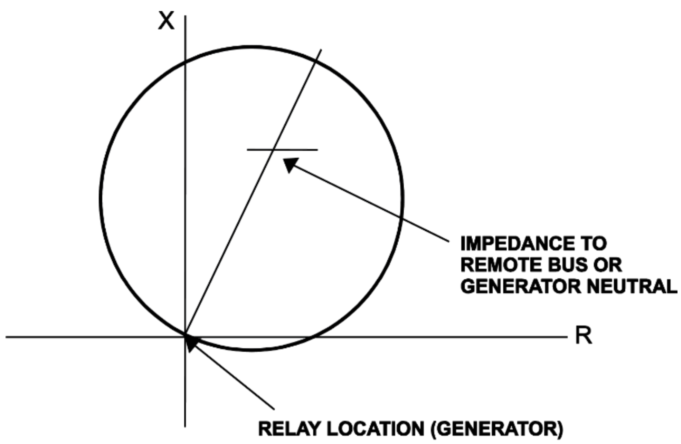


Figure 18. Impedance Relay, Looking for Remote Line Faults

4. Reverse Power Protection

The reverse-power element (32) in Figure 19 senses real power flow into the generator, which occurs if the generator loses its prime mover input. Because the generator is not faulted, CTs on either side of the generator provide the same measured current.

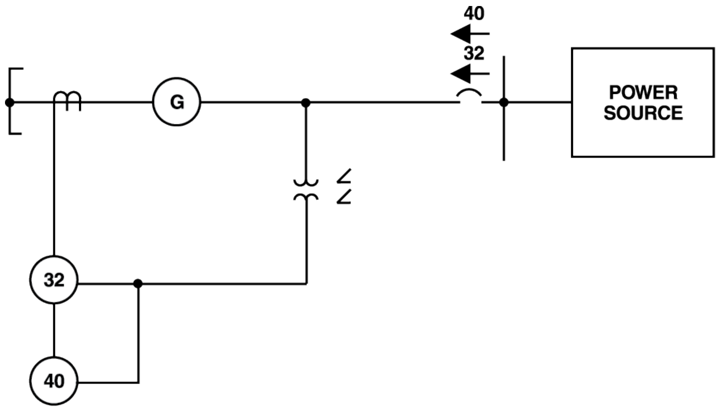


Figure 19. Anti-Motoring (32), Loss of Field (40), Protection

In a steam turbine, the low-pressure blades will overheat with the lack of steam flow. Diesel and gas turbine units draw large amounts of motoring power with possible mechanical problems. In the case of diesels, the hazard of a fire and/or explosion may occur because of unburned fuel. Therefore, anti-motoring protection is recommended whenever the unit might be connected to a source of motoring power. Where a non-electrical type of protection is in use, as can be the case with a steam turbine unit, the 32 function provides a way of supervising this condition to prevent opening the generator breaker before the prime mover has shut down. Delay should be set for about 5-30 seconds to provide enough time for the controls to pick up load upon synchronizing when the generator is initially slower than the system.

Motoring can occur with large reactive power flow. Figure 20 illustrates a generator-producing load at 0.8PF. When the prime mover is lost, power reverses to motoring levels (10% in this case). However, the excitation system maintains constant var levels, causing the power factor to drop to 0.08PF.

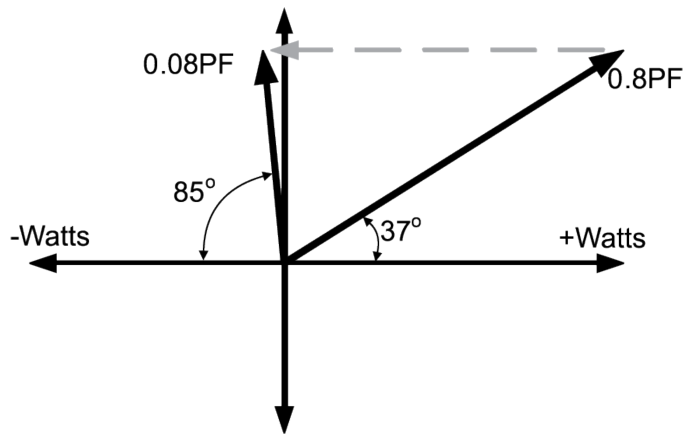


Figure 20. Example of High Var/Low PF Flow

Digital relays are better than single- function relays at responding to lower power factors. The BE1-FLEX relay can detect generator motoring reliably at power factors as low as 0.025 or 88.6 degrees.

Figure 21 shows the use of two reverse power functions: 32-1 and 32-2. The 32-1 function supervises the generator tripping of devices that can wait until the unit begins to motor. Over speeding on large steam-turbine units can be prevented by delaying main and field breaker tripping until motoring occurs for non-electrical and selected electrical conditions (e.g., loss-of-field and over temperature). Function 32-1 should be delayed approximately 3 seconds, while element 32-2 should be delayed by approximately 20 seconds. Time delay is based on generator response during generator power swings. Function 32-2 trips directly for cases of motoring that were not initiated by a lockout protection 86NE — e.g., governor controls malfunction.

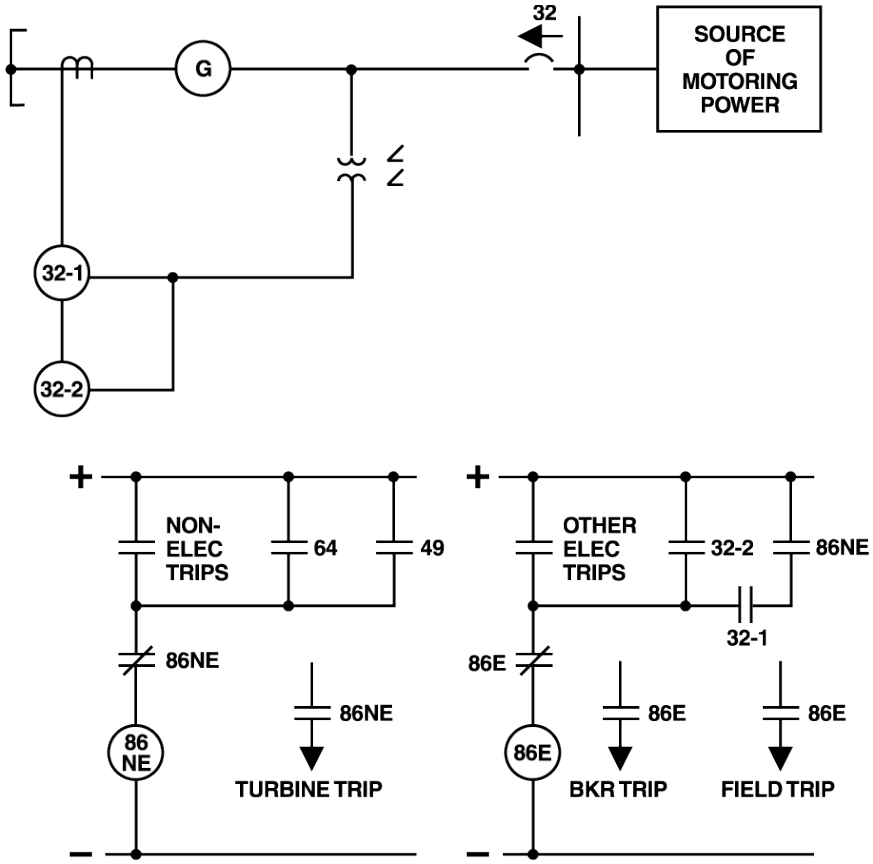


Figure 21. Reverse Power Function 32-1 Prevents Load Rejection before Prime Mover Shutdown for Selected Trips; Function 32-2 Operates if Motoring is Not Accompanied by an 86NE Operation

5. Loss of Field Protection

Loss of excitation can be sensed, to some extent, within the excitation system itself by monitoring for loss of field voltage or current. For generators that are paralleled to a power system, the preferred method is to monitor for loss of field at the generator terminals. When a generator loses excitation power, it appears to the system as an inductive load, and the machine begins to absorb a large amount of vars. Loss of field can be detected by monitoring for var flow (40Q) or apparent impedance (40Z) at the generator terminals.

The power diagram (P-Q plane) of Figure 22 shows the Basler BE1-FLEX (40Q element) with a representative setting, a representative generator thermal capability curve, and an example of the trajectory following a loss of excitation. The first quadrant of the diagram applies for lagging power factor operation (generator supplies vars). The trajectory starts at point A and moves into the leading power factor zone (4th quadrant), and can readily exceed the thermal capability of the unit. A trip delay of about 0.2-0.3 seconds is recommended to prevent unwanted operation because of other transient conditions. A second high-speed trip zone might be included for severe underexcitation conditions.

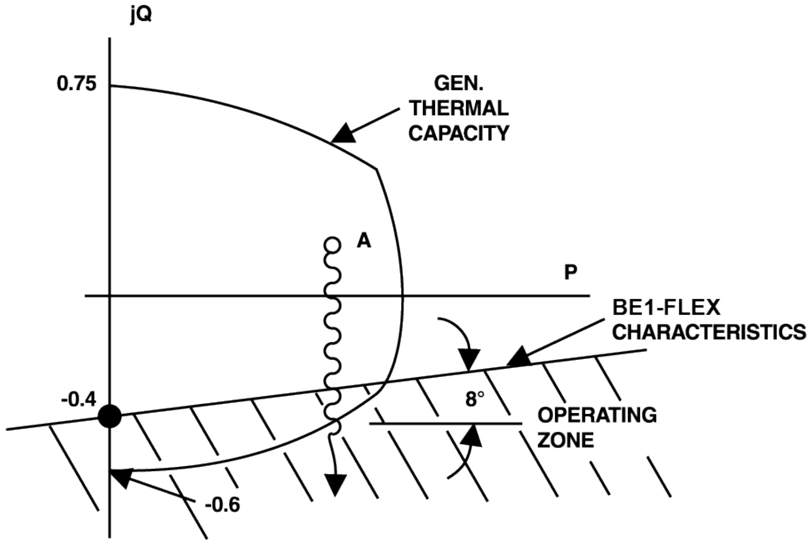


Figure 22. For Loss of Field, the Power Trajectory Moves from Point A into the Fourth Quadrant

When impedance based relaying, such as the 40Z element in the BE1-FLEX, is used to sense loss of excitation, the trip zone is typically a mho circle centered about the X axis, offset from the R axis by X'd/2 and the lower edge offset from the R axis by 1.1 • Xd. Two zones are used: a high-speed zone and a time-delayed zone. See Figure 23.

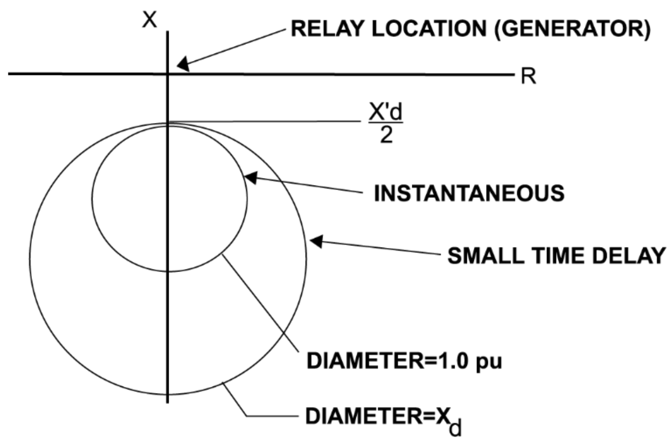


Figure 23. Loss of Excitation using Impedance Relay

With complete loss of excitation, the unit will eventually operate as an induction generator with a positive slip. Because the unit is running above synchronous speed, excessive currents can flow in the rotor, resulting in overheating of elements not designed for such conditions. This heating cannot be detected by thermal element 49, which is used to detect stator overloads.

Rotor thermal capability also can be exceeded for a partial reduction in excitation because of an operator error or regulator malfunction. If a unit initially generates reactive power and then draws reactive power upon loss of excitation, the reactive swings can significantly depress the voltage. In addition, the voltage will oscillate and adversely affect sensitive loads. If the unit is large compared to the external reactive sources, it can result in system instability.

6. Thermal Protection

Figure 24 shows the Basler BE1-FLEX connected to a resistance temperature detector embedded in a stator slot. The RTDs can be either two- or three-wire. The BE1-FLEX has user settings for a variety of RTD types. RTD metering data is displayed on the BE1-FLEX.

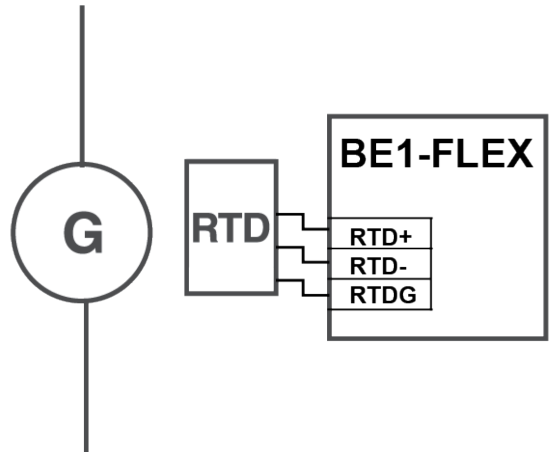


Figure 24. Stator Temperature Protection

Two methods used to detect loss of VTs are voltage balance between two VTs and voltage- current comparison logic.

Figure 25 shows the use of two sets of VTs on the generator terminals with the 60FL function comparing the output of the two VTs via configurable protection in the BE1-FLEX. One set supplies the voltage regulator, the other, the relays. If the potential decreases or is lost from VT No. 1, the BE1-FLEX disables the voltage regulator; if source No. 2 fails, the BE1-FLEX blocks relay tripping of the 21, 27, 59N and 47. In some applications, the 25, 32, and 40 elements are also blocked. Overexcitation protection (24), phase overvoltage (59) and frequency relaying (81) do not need to be blocked because loss of potential leads toward nonoperation of these functions.

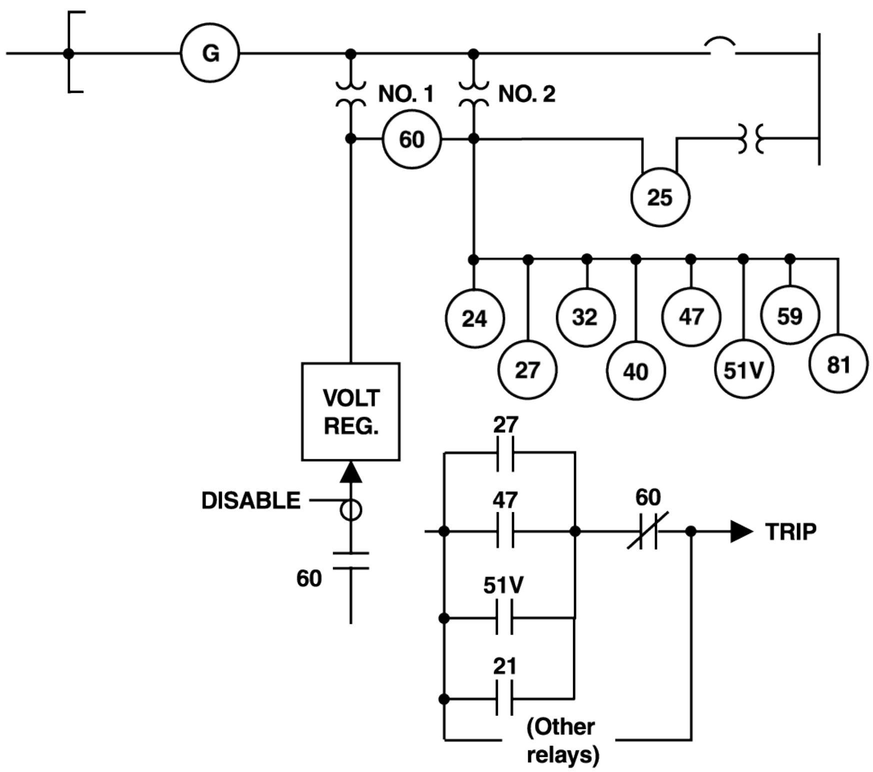


Figure 25. Various Voltage Protection Elements. Voltage-Balance Element (60) Detects Potential Supply Failure

Another means of detecting fuse loss is by comparing voltage and current (Figure 26). The 60FL element of the Basler BE1-FLEX detects fuse loss and loss of potential by using voltage and current thresholds that are expressed as a percentage of the nominal voltage and current values. In a single-phase or two-phase fuse loss, voltage imbalance exists without the corresponding current imbalance that would exist during an actual fault. In a three-phase fuse loss, complete voltage loss occurs without the corresponding three-phase current flow that would occur during a fault. To prevent a 60FL from being declared during loss of station power, it might be necessary to allow a three-phase 60FL to be declared only when some low level of load current exists.

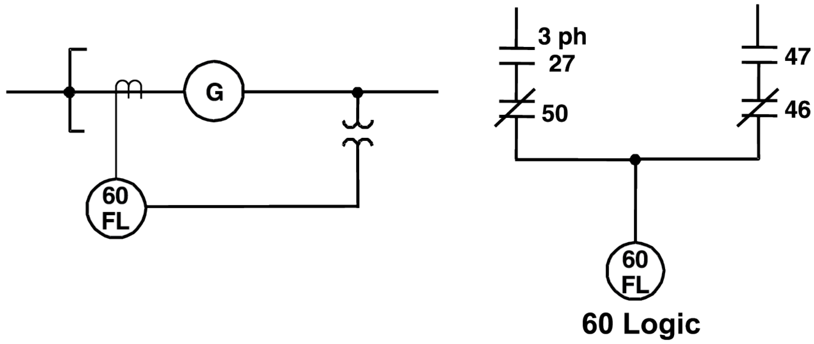


Figure 26. Loss of Fuse Detection, 60FL, Alternate Method

7. Overexcitation and Over/Under Voltage Protection

Overexcitation can occur because of higher than rated voltage, or rated or lower voltage at less than rated frequency. For a given flux level, the voltage output of a machine will be proportional to frequency. Because maximum flux level is designed for normal frequency and voltage, when a machine is at reduced speed, maximum voltage is proportionately reduced. A volts/hertz function (24) responds to excitation level as it affects thermal stress to the generator (and to any transformer tied to that generator). IEEE C50.13 specifies that a generator should continuously withstand 105% of rated excitation at full load.

With the unit offline and with voltage regulator control at reduced frequency, the generator can be overexcited if the regulator does not include an overexcitation limiter. Overexcitation can also occur, particularly with the unit offline, if the regulator is out of service or defective. If voltage-balance supervision (60) is not provided and a fuse blows on the regulator ac potential input, the regulator would cause overexcitation. Loss of ac potential may also fool the operator into developing excessive excitation. The 24 function can protect only for overexcitation resulting from an erroneous voltage indication if the 24 function is connected to an ac potential source different from that used for the regulator.

Figure 27 shows the relation of the Basler BE1-FLEX relay with voltage element inverse-squared characteristics and an example of a generator and transformer withstand capability. Generator and transformer manufacturers should supply the specific capabilities of these units.

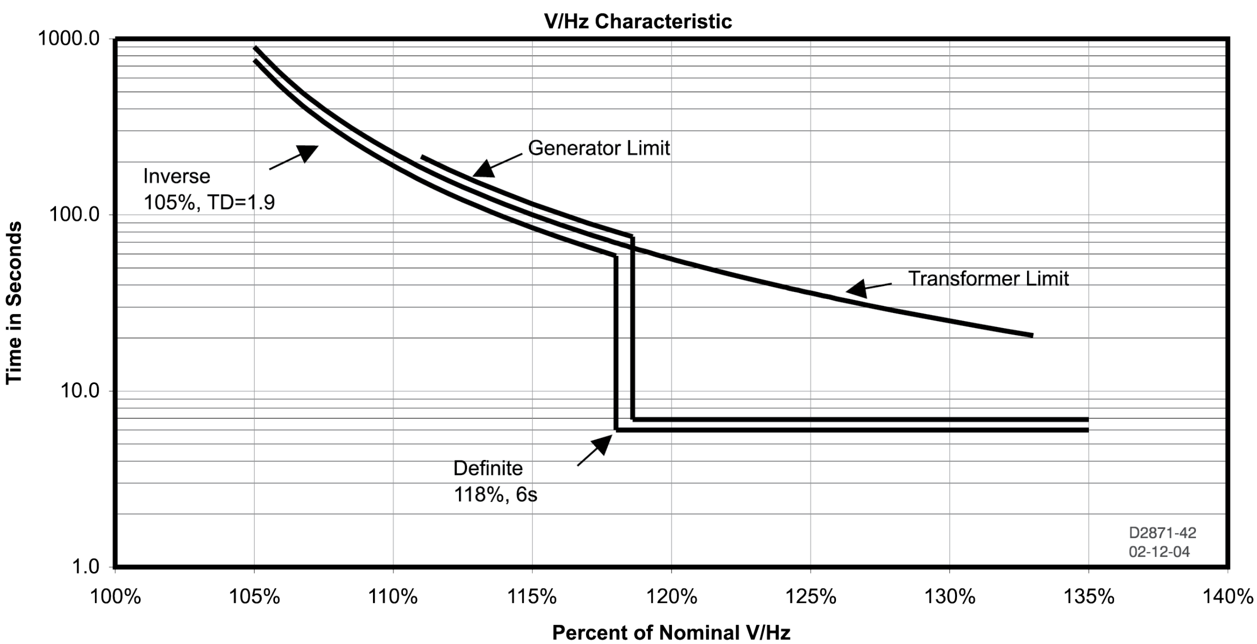


Figure 27. Combined Generator/Transformer Overexcitation Protecting using both the Inverse Squared and Definite Time Tripping. Equipment Withstand Curves are Examples Only.

Phase over (59) and under (27) voltage protection also acts as a backup for excitation system problems. Undervoltage protection also acts as fault detection protection, because faults tend to depress voltage.

8. Off-Frequency Operation

Diesel engines can be safely operated off normal frequency, and minimal protection is required. Turbine controls generally provide protection for off frequency conditions, but relaying should be provided to protect the turbine and generator during control system failure. Often, frequency relays are applied with steam-turbine units, particularly to minimize turbine blade fatiguing. IEEE C37.106, Ref. 3 specifically addresses abnormal frequency operation and shows typical frequency operating limits specified by various generator manufacturers. The simplest relay application would be a single underfrequency stage, but a multiple stage and multiple set point arrangement are advantageous. Each set point can be set to recognize either overfrequency or underfrequency. Any number of frequency setpoints is available, up to the maximum total capacity as shown in BESTCOMS*Plus*® software, in the BE1-FLEX.

Another common need for frequency relaying is detecting generation that has become isolated from the larger utility system grid. When a generator is connected to the utility, generator frequency is held tightly to system frequency. Upon islanding, the generator frequency varies considerably as the governor works to adjust generator power output to local loads. If the generator frequency varies from nominal, islanding is declared and either the generator is tripped or the point of common coupling with the utility is opened.

9. Inadvertent Energization Protection

Inadvertent energization can result from a breaker interrupter flashover or a breaker close initiation while the unit is at standstill or at low speed. The rapid acceleration can do extensive damage, particularly if the generator is not promptly de-energized. While relays applied for other purposes may eventually respond, they are not generally considered dependable for responding to such an energization.

Undervoltage supervised overcurrent (50/27) or frequency supervised overcurrent (50/81) protection can be used to provide inadvertent energization protection. Figure 28 and Figure 29 show these two methods of detecting the energization of a machine at standstill or at a speed significantly lower than rated. This situation could be caused by single-phase energization because of breaker-interrupter flashover or three-phase energization because of breaker closure. The unit, without excitation, will accelerate as an induction motor with excessive current flow in the rotor. Both Figure 28 and Figure 29 schemes will function properly with the VT fuses at the generator terminal removed. With the generator offline, safety requirements might dictate the removal of these VT fuses. In the case of Figure 28, the overcurrent protection is enabled by undervoltage units and works as long as 60FL logic does not block the trip path. In Figure 29, the potential is taken from bus VTs, rather than unit VTs, so the scheme will function even if the VT fuses are removed during unit maintenance.

In Figure 28, the terminal voltage will be zero prior to energization, so the 27 and 81U function contacts will be closed to energize the timer (62). The instantaneous overcurrent element (50) trip circuit is established after timer 62 operates. Upon inadvertent generator energization, the undervoltage and underfrequency element contacts can open because of the sudden application of nominal voltage and frequency, but the delayed dropout of 62 allows function 50 to initiate tripping. The use of a 60FL function or two 27 elements on separate VT circuits avoids tripping for a VT fuse failure. Alternatively, a fuse loss detection or voltage-balance element (60) could be used in conjunction with a single 27 function to block tripping.

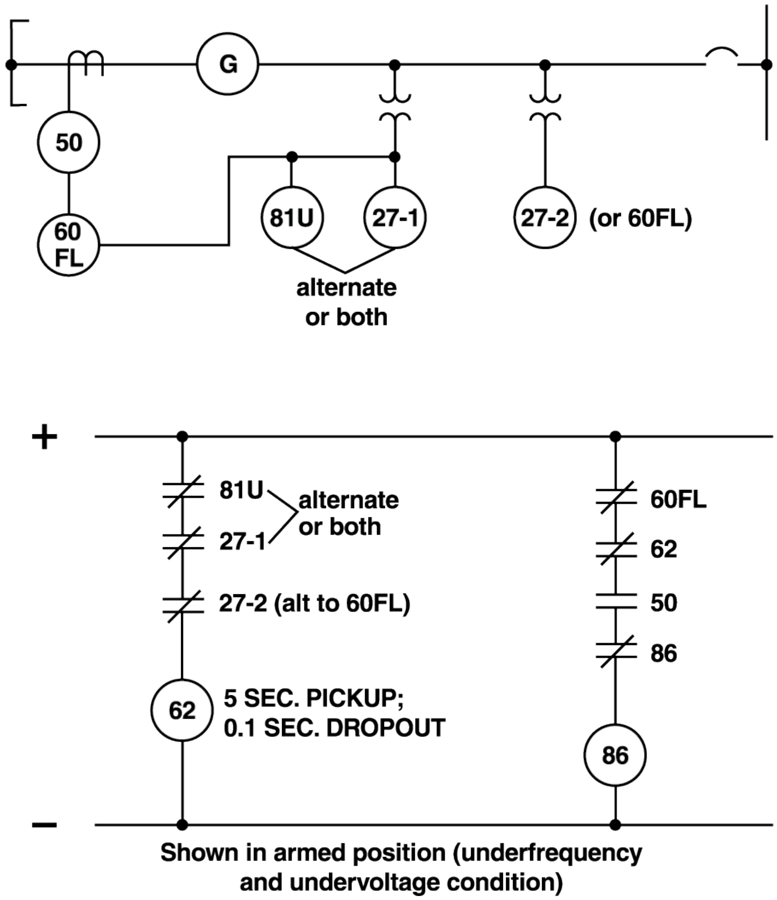


Figure 28. Inadvertent Energization Protection using Instantaneous Overcurrent Function (50)

In Figure 28, the five-second pickup delay on timer 62 prevents tripping for external disturbances that allow dropout of the 27 protection. The 27 protection should be set at 85% voltage (below the operating level under emergency conditions). The Figure 29 scheme could be employed where protection independent of the plant is desired. In this case, the BE1-FLEX relay system would be placed in the switchyard rather than in the control room. While directional overcurrent (67) should be delayed to ride through synchronizing surges, it can still provide fast tripping for generator faults, because the 67 functions need not be coordinated with external protection. Figure 29 shows the operating one line for the BE1-FLEX relay system using the directional overcurrent element (67).

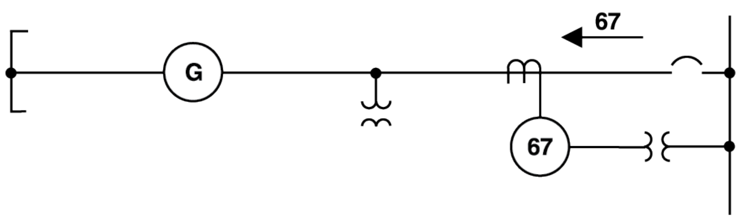


Figure 29. The Directional Overcurrent Element of the BE1-FLEX Inadvertent Energization (IE)

10. Negative-Sequence Protection

Negative-sequence stator currents, caused by fault or load unbalance, induce double-frequency currents into the rotor that can eventually overheat elements not designed to be subjected to such currents. Series unbalances, such as untransposed transmission lines, produce some negative-sequence current (I_2) flow. The most serious series unbalance is an open phase, such as an open breaker pole. ANSI C50.13-1977 specifies a continuous I2 withstand of 5 to 10% of rated current, depending upon the size and design of the generator. These values can be exceeded with an open phase on a heavily loaded generator. The Basler BE1-FLEX relay protects against this condition, providing negative-sequence inverse-time protection shaped to match the short-time withstand capability of the generator should a protracted fault occur. This is an unlikely event, because other fault sensing relaying tends to clear faults faster, even if primary protection fails.

Figure 30 shows the 46 function connection. CTs on either side of the generator can be used, because the relay protects for events external to the generator. The Basler BE1-FLEX can also alarm to alert the operator to the existence of a dangerous condition.

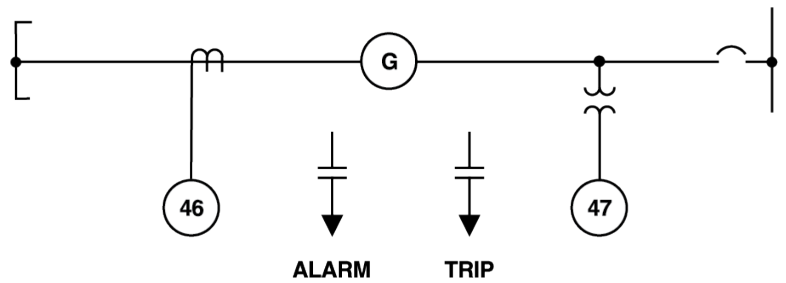


Figure 30. Negative-Sequence Current Element (46) Protects Against Rotor Overheating due to a Series Unbalance or Protracted External Fault. Negative-Sequence Voltage Element (47) (Less Commonly Applied) also Responds.

Negative sequence voltage (47) protection, while not as commonly used for generator protection, is another means to sense system imbalance as well as, in some situations, a misconnection of the generator to a system to which it is being paralleled.

11. Out-of-Step Protection

Out-of-step, or pole slipping, is the loss of synchronism of a generator relative to the system. Typically, this condition is caused by an external, slow clearing three-phase fault allowing the machine to accelerate and slip poles. Under this condition, there are high current and mechanical forces on the generator windings and high levels of transient shaft torques. Out-of-step (78OOS) protection uses impedance techniques to sense this condition. The relay sees an apparent load impedance swing as impedance moves from Zone 1 to Zone 2 (Figure 31). The moving impedance is identified as a swing rather than a fault so fault detection relaying may be blocked. The time it takes for the load impedance to traverse from Zone 1 to Zone 2 is used to decide if an out-of-step condition exists.

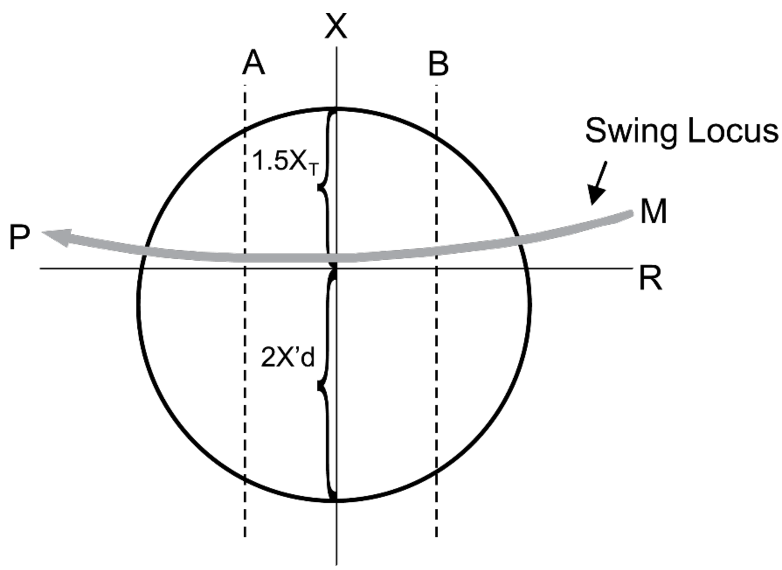


Figure 31. Out-of-Step Protection (78OOS)

Out-of-step (78) protection should be provided on any generator if the electrical center of the swing passes through the region from the high-voltage terminals of the step-up transformer down into the generator. It should also be provided if the electrical center is out in the system and the system relays are blocked or not capable of detecting the out-of-step condition.

The use of a single blinder scheme can be implemented in the BE1-FLEX to minimize the probability of tripping on recoverable swings.

The need for 78OOS protection must be determined by a system stability study, which is typically conducted by the utility to which the generator is connected. Utility interconnection agreements and power pool agreements may affect the need for this protection.

12. Selective Tripping and Sequential Tripping

Some generators selectively trip the prime mover, the field, and the generator breaker, depending on the type of fault that is detected. For instance, if the generator is protected by a 51V and an 87, and only the 51V trips, it might be assumed that the fault is external to the generator and, therefore, the 51V only trips the generator breaker and rapidly pulls back the excitation governor and prime mover setpoints. However, if there is no 87, the 51V trips the entire unit. Associated with this concept, is sequential tripping, used for orderly shutdown. To prevent overspeeding a generator during shutdown, it is sometimes a practice to trip the prime mover first and trip the main breaker and field only after a reverse power (32) element verifies the prime mover has stopped providing torque to the generator.

13. Synchronism Check and Auto Synchronizing

Before connecting a generator to the power system, it is important that the generator and system frequency, voltage magnitude and phase angle be in alignment, referred to as synchronism checking (25). Typical parameters are shown in Figure 32. Typical applications call for no more than 6 RPM error, 2% voltage magnitude difference and no more than 10° phase angle error before closing the breaker. The Basler BE1-FLEX can perform the sync check function.

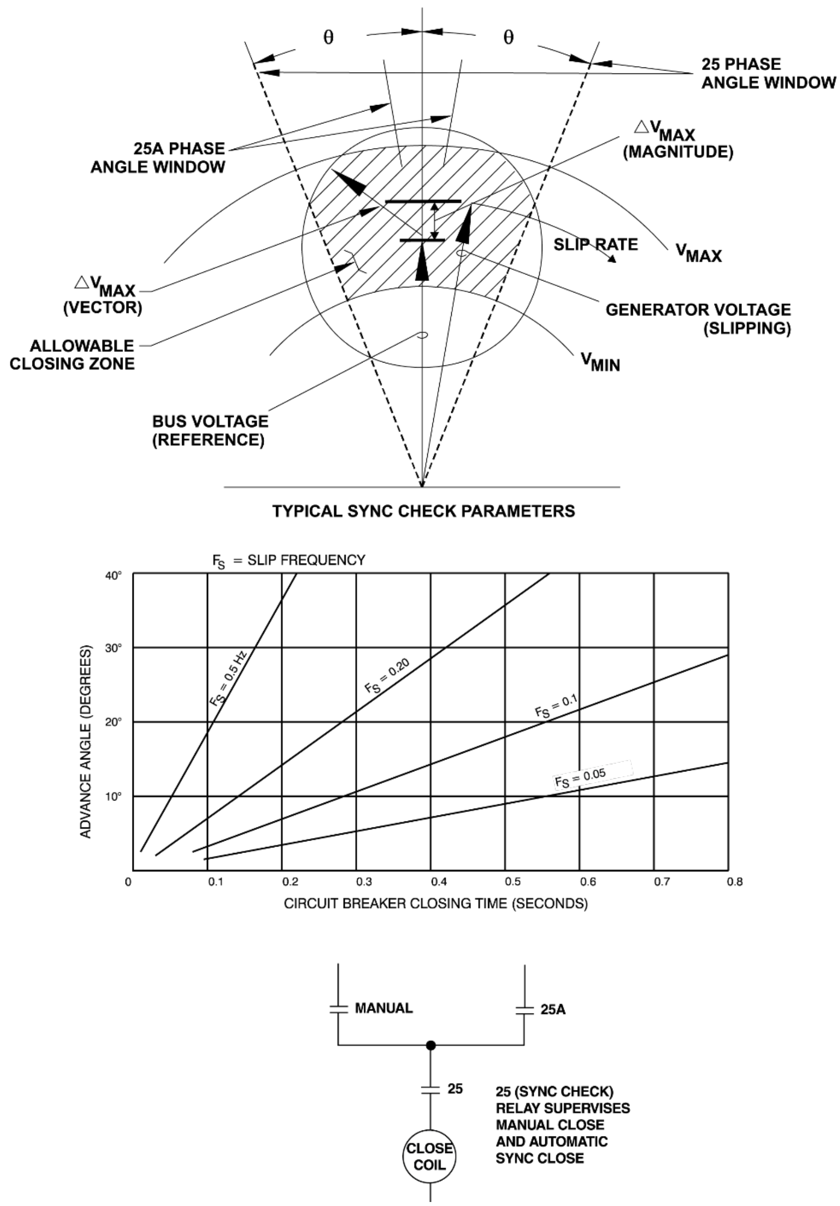


Figure 32. Synchronizing Parameters: Slip, Advance Angle, and Breaker Closing Time

Auto synchronizing (25A) refers to a system to automatically bring a generator into synchronism with the power system. It involves sending voltage and speed raise and lower commands to the voltage regulator and prime mover governor. When the system is in synchronism, the auto sync element is designed to send a close command in advance of the zero-phase angle error point to compensate for breaker close delays. Typically, the 25 function, which usually is set to supervise the 25A and manual sync function, is set with wider parameters than the 25A to coordinate with the actions of the 25A. The auto-synchronization feature is available in the Basler BE1-FLEX as an option. The BE1-FLEX can also be used for sync check, commonly from a second device for redundancy.

14. Integrated Application Examples

Figures 33 through 37 show examples of protection packages.

Figure 33 represents bare-minimum protection, with only overcurrent protection. Generators with such minimum protection are uncommon in this era of microprocessor-based multifunction relays. Such protection would likely be seen only on very small (< 50 kVA) generators used for standby power that is never paralleled with the utility grid or other generators. It might appear to be a disadvantage to use CTs on the neutral side as shown, because the relays might operate faster with CTs on the terminal side. The increase in speed would be the result of a larger current contribution from external sources. However, if the CTs are located on the terminal side of the generator, there will be no protection prior to putting the machine online. This is not recommended, because a generator with an internal fault could be destroyed when the field is applied.

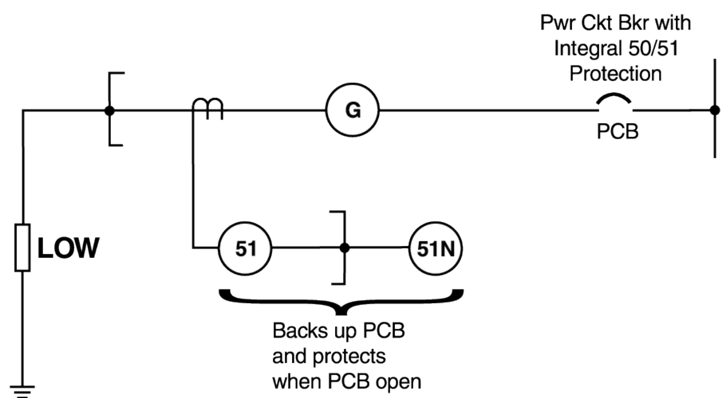
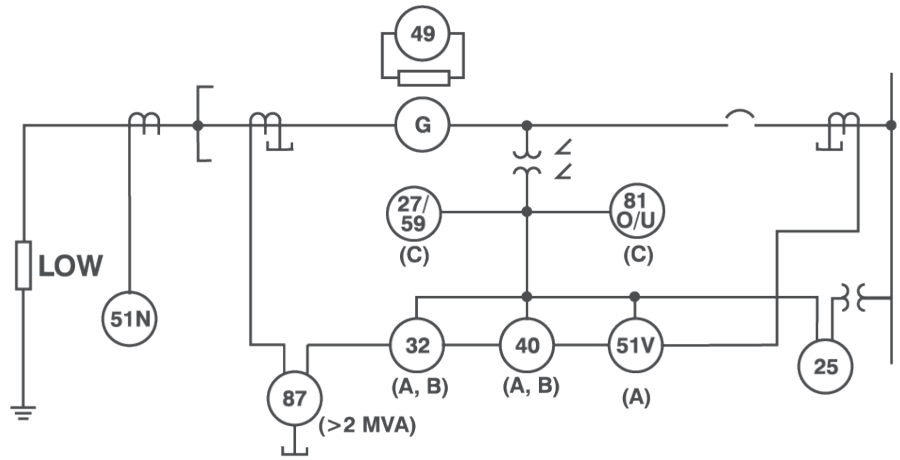


Figure 33. Example of Bare-Minimum Protection (Low-Impedance Grounding)

Figure 34 shows the suggested minimum protection with low-resistance grounding. It includes differential protection, which provides fast, selective response, but differential protection becomes less common as generator size decreases below 2 MVA, on 480 V and less units and on generators that are never paralleled with other generation. The differential element responds to fault contributions from both the generator and the external system. While the differential element is fast, the slow decay of the generator field will cause the generator to continue feeding current into a fault. However, fast relay operation will interrupt the external source contribution, which might be greater than the generator contribution. Fast disconnection from the external source allows prompt restoration of normal voltage to loads and can reduce damage and cost of repairs.



(A) CONNECT TO NEUTRAL-SIDE CTS IF NO EXTERNAL POWER SOURCE OR NO 87B.

(B) OMIT IF NO EXTERNAL POWER SOURCE.

(C) LESS CRITICAL.

Figure 34. Suggested Minimum Protection Example (Low-Impedance Grounding)

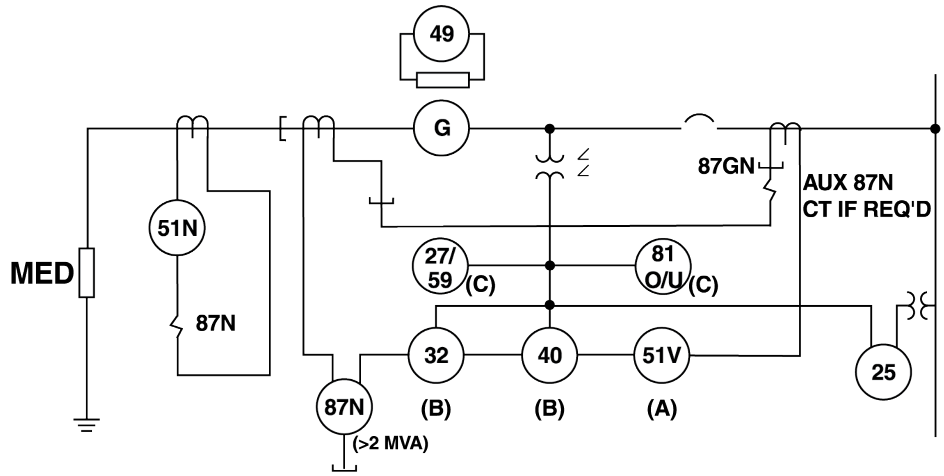
The differential element (87) can protect for ground faults, depending upon the grounding impedance. The 51N function in Figure 34 provides backup protection for the 87 or will be the primary protection if the differential protection (87) is not sufficiently sensitive to the ground current level.

The 51V voltage-controlled or voltage-restrained time overcurrent protection in Figure 34 is shown on the CT on the high-voltage/system side of the generator. This allows the relay to see system contributions to a generator fault. It provides backup for the differential element (87) and for external relays and breakers. Because it is monitoring CTs on the system side of the generator, it will not provide backup coverage prior to having the unit online. If there is no external source, no 87, or if it is desired that the 51V provides generator protection while the breaker is open, connect the 51V to the neutral-side CTs.

Figure 34 shows three relays sharing the same CTs with a differential element. This is practical with solid-state and digital relays, because the low burden will not significantly degrade the quality of differential relay protection. The common CT is not a likely point of failure of all connected relaying. A CT wiring error or CT short is unlikely to disable both the 87 and 51V elements. Rather, a shorted CT or defective connection will unbalance the differential circuit and cause the 87 to trip. Independent CTs could be used to provide improved backup protection, although this seems to be a minimal advantage. However, a separate CT is used for the 51N function that provides protection for the most likely type of fault.

The reverse power function (32) in Figure 34 protects the prime mover against forces from a motored generator and could provide important protection for the external system if the motoring power significantly reduces voltage or overloads equipment. Likewise, the loss-of-field protection (40) has dual protection benefits against rotor overheating and against depressed system voltage because of excessive generator reactive absorption. Thermal relay (49) protects against stator overheating because of protracted heavy reactive power demands and loss of generator cooling. Even if the excitation system is equipped with a maximum excitation limiter, a failure of the voltage regulator or a faulty manual control could cause excessive reactive power output. Frequency relaying (81O/U) protects the generator from off nominal frequency operation and senses generator islanding. The under and overvoltage function (27/59) detects excitation system problems and some protracted fault conditions.

Figure 35 shows minimum basic protection for a medium-impedance grounded generator. It differs from Figure 34 only in the use of a ground differential element (87N, part of BE1-FLEX). This protection provides faster clearing of ground faults where the grounding impedance is too high to sense ground faults with the phase differential function (87). The function compares ground current seen at the generator high-voltage terminals to ground current at the generator neutral. The 51N element provides backup for the ground differential (87N) and for external faults, using the current polarizing mode. The polarizing winding measures the neutral current.



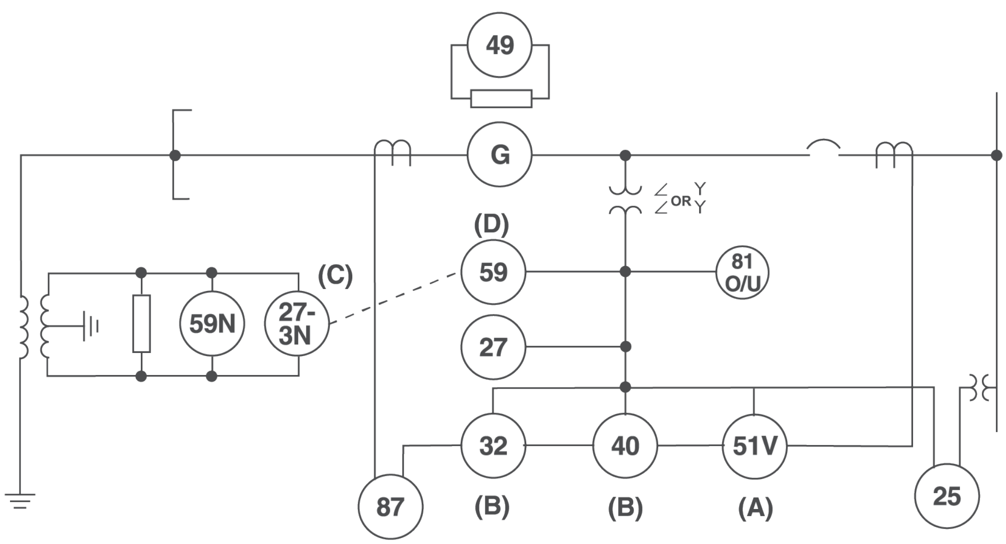
(A) CONNECT TO NEUTRAL-SIDE CTS IF NO EXTERNAL POWER SOURCE.

(B) OMIT IF NO EXTERNAL POWER SOURCE.

(C) LESS CRITICAL.

Figure 35. Suggested Minimum Protection Example (Medium-Impedance Grounded)

Figure 36 shows minimum basic protection for a high-impedance grounded generator. It differs from Figure 34 only in the ground relay protection and the method of grounding. The voltage units 59N and 27-3N provide the ground only protection, because the ground fault current is too small for phase differential protection (87) operation. The 59N element will not be selective if other generators are in parallel, because all the 59N elements will see a ground fault and operate nominally at the same time. If three-phase ground Y-Y VTs were applied in Figure 36, the 27 and 59 could provide additional ground fault protection, and an additional generator terminal 59N ground-shift protection could be applied.



(A) CONNECT TO NEUTRAL-SIDE CTS IF NO EXTERNAL POWER SOURCE.

(B) OMIT IF EXTERNAL POWER SOURCE.

(C) INCLUDED IN BE1-59N RELAY.

(D) SUPERVISES 27-3N TRIP.

Figure 36. Suggested Minimum Protection Example (High-Impedance Grounding)

The Basler BE1-FLEX includes a third-harmonic undervoltage function (27-3N) that provides supervision of the grounding system, protects for faults near the generator neutral and detects a shorted or open connection in the generator ground connection or in the distribution transformer secondary circuit.

Figure 37 shows the application of additional elements for extended protection: overexcitation element (24), negative-sequence overcurrent and overvoltage element (46 and 47), ground overcurrent protection (51GN), voltage balance relay (60), field ground function (64F), frequency element (81) and the 27/50/62 element combination for inadvertent energization protection. Element 51GN provides a second method to detect stator ground faults or faults in the generator connections or faults in the delta transformer windings. Differential protection 87T and sudden pressure element 63 protect the unit step-up transformer. Element 51N provides backup for external ground faults and for faults in the high-voltage transformer windings and leads. This function may also respond to an open phase condition or a breaker-interrupter flashover that energizes the generator. The 51N function will be very slow for the flashover case, because it must be set to coordinate with external relays and is a last-resort backup for external faults.

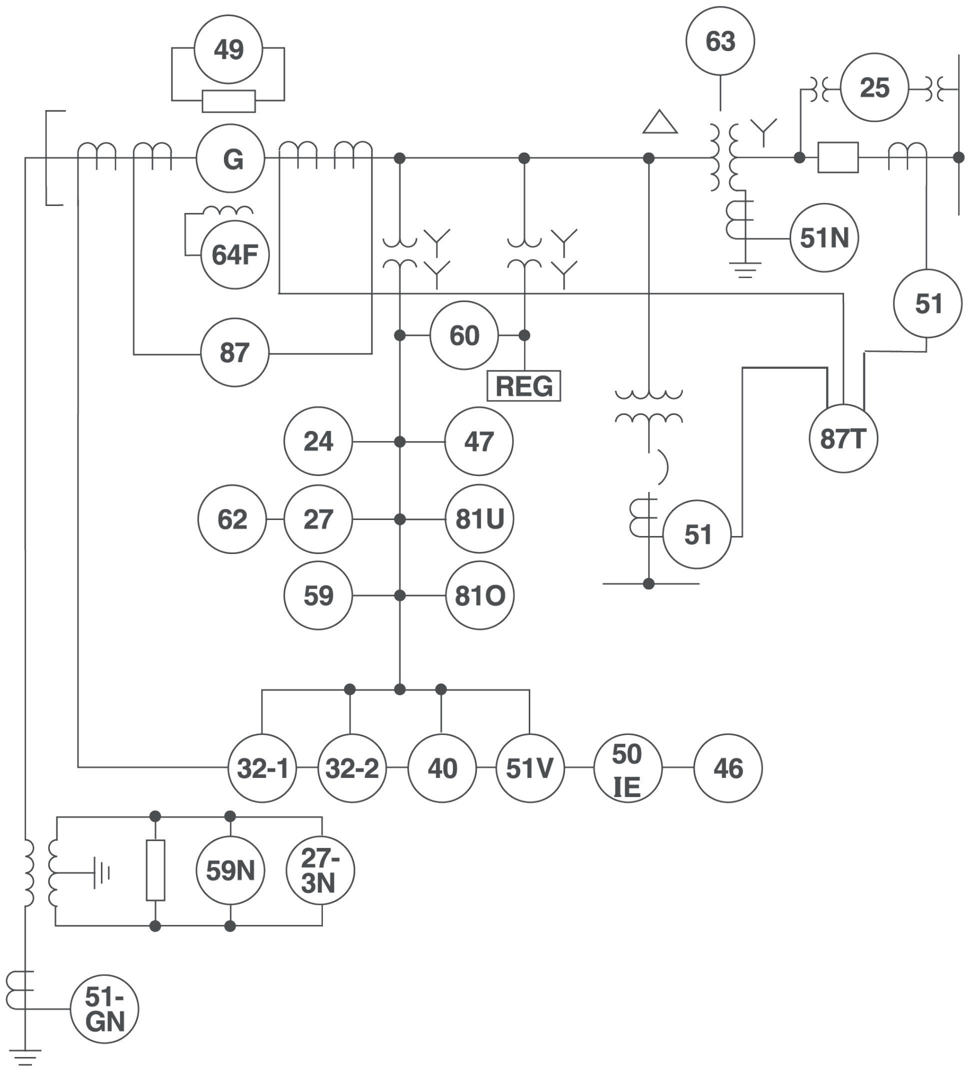


Figure 37. Wye-Connected VTS, Appropriate with an Isolated-Phase Bus

15. Application of Digital Protection Relays

Digital programmable relays contain many of the functions discussed in this guideline in a single package. Figures 38 and 39 show the BE1-FLEX applied to generator protection. Because of logic complexity, full details are not shown. Details of these applications can be found in the application templates from www.basler.com.

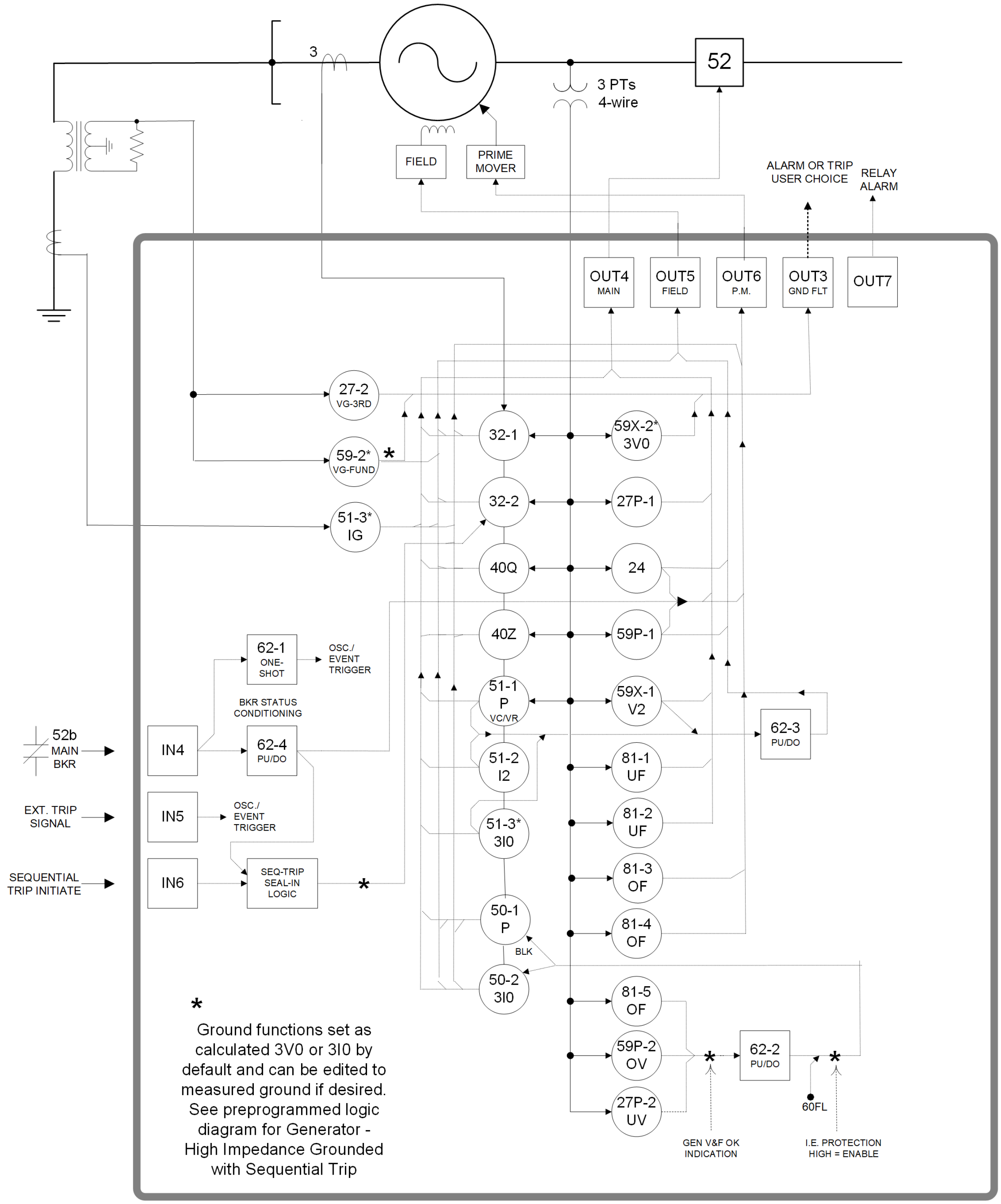


Figure 38. High Impedance Grounded Generator with Sequential Trip One Line

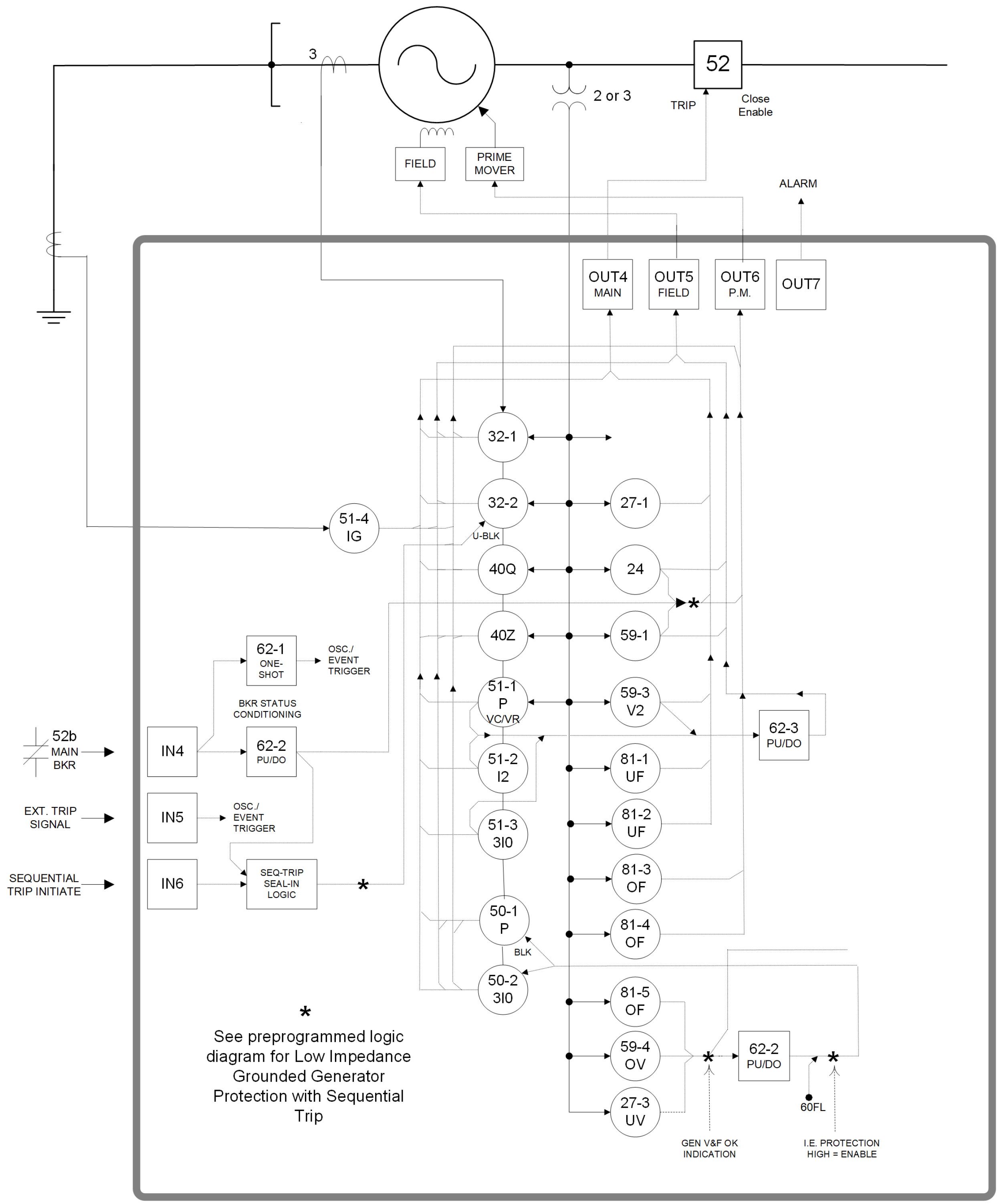


Figure 39. Low Impedance Grounded Generator Protection with Sequential Trip One Line

16. Typical Settings and Relays

Table 1 is an example of the typical specifications supplied by the manufacturer and/or designer. This data is used to derive typical settings for use as a starting point in the setting determination procedure. The proper settings are heavily influenced by the specifics of each application. Typical settings also are used as an aid in selecting the range where a choice is available.

Table 1. Example of Typical Specifications

Generator Nameplate Data[1]	
Prime Mover	Diesel Engine
RPM	1800
Frequency	60 Hz
kW	2000
kVA	2500
Power Factor	0.8
Line Voltage	480
Rated Current	3007
Phases	3
Connection	Series Star
Number of Leads	3 Phase and 3 Neutral
Poles	4
Generator Pitch	0.6667
Exciter Source	Permanent Magnet
Excitation Volts	43.66
Excitation Amps	3.3
CT and VT Ratios[1]	
CTR	1200:5
VTR	4:1

(1) Any power system and measurement parameters including nameplate data, CT or VT ratios should be configured when using digital relays prior to modifying protection settings and making them active. To follow the example, please visit www.basler.com to download configuration software BESTCOMS*Plus*®. See the BE1-FLEX instruction manual (publication 9579200990) for additional details.

Table 2 lists the functions discussed herein as applied to a 2 MW diesel generator set in configuration software BESTCOMS*Plus*® for the BE1-FLEX Protection, Automation and Control System.

Table 2. Typical Settings[1]

IEEE No.	Fig.	Function	Typical Settings and Remarks	BE1-FLEX BESTCOMS*Plus*® Settings[2]
24	25, 27	Overexcitation	PU: 1.2 • V/Hz; Time Delay: 60 s; Alarm PU: 1.1 • V/Hz; Alarm delay: 6 s	Definite Time Timer 1 PU: 2.40; Timer 1 Time Delay: 60000; Alarm Pickup: 2.20; Alarm Time Delay: 6000
25	25, 32	Synchronism Check	Max Slip: 6 RPM; Max phase angle error: 10°; Max V error: 2.5% V	Voltage Diff: 2; Slip Angle: 10; Slip Freq: 0.10
32	19, 21	Reverse Power (one stage)	PU: turbine 1% of rated; 15 s; PU: Reciprocating engine: 10% of rated; 5 s	32-1 element mode: Total Power; PU: 83; Time Delay: 5000; Direction: Reverse; Over Under: Over
32-1	21	Reverse Power Nonelectrical Trip Supervision	PU: same as 32; 3 s	32-2 element same as 32-1 with Time Delay: 3000
40	19, 22	Loss of field (var flow approach)	Level 1 PU: 25% VA rating; Delay: 0.2 s; Level 2 PU: 40% VA rating; Delay: 0.1 s	PU: 625.5; Time Delay: 200
46	30	Negative-Sequence Overcurrent	I PU: 10% I; K = 10	51-1 element mode: I2; Source: Stator output; PU: 0.500; Time Dial: 10; Curve: 46 – K Factor

IEEE No.	Fig.	Function	Typical Settings and Remarks	BE1-FLEX BESTCOMS*Plus*® Settings[2]
49	24	Stator Temperature (RTD)	Lower: 95°C; Upper: 105°C	49RTD-1[3] element mode: Under; Source: RTD Group 1; PU[4]: 95; Time Delay: 0; Voting: 1 49RTD-2[3] element mode: Over; Source: RTD Group 1; PU[4]: 105; Time Delay: 0; Voting: 1
50/27 IE	28	Inadvertent Energization Overcurrent with 27, 81 Supervision	50: 10% I 27: 85% V (81: Similar)	50-1 element mode: 3 Phase; Source: Stator output; PU: 0.500; Time Delay: 0 27P-1 element mode: One of Three; PU: 58.9 Vpn; Inhibit Level: 0.0 Vpn; Timing Mode: Definite Timing; 81-1 element mode: Under; Source: Phase VT; PU: 51; Time Delay: 0; Voltage Inhibit: 0.0 Vpn[5]
50/51N	2	Stator Ground Overcurrent (Low-, Med.-Z Gnd, Neutral CT or Flux Summation CT)	PU: 10% I; Curve E1; TD4; Inst 100% I. Higher PU if required to coordinate with load. No higher than 25% I.	51-2 element mode: IG; Source: IG; PU : 0.500; Time Dial: 4.00; Curve: E1 50-2 element mode: IG; Source: IG; PU 5.010; Time Delay: 0
51VR	11	Voltage Restrained Overcurrent	PU: 175% I; Curve: V1; TD: 4. Zero Restraint Voltage: 100% V.	51-3 element mode: 3 Phase; Source: Stator output; PU: 8.26; Time Dial: 4.00; Curve: V1; Voltage Restraint Mode: Restraint; Threshold: 69 Vpn
81	25	Over/Underfrequency	Generator protection: 57 Hz, 62 Hz, 0.5 s; Island detection: 59 Hz, 61 Hz, 0.1 s	81-2 element mode: Under; PU: 57; Time Delay: 500; Voltage Inhibit: 0.0; 81-3 element mode: Over; PU: 62; Time Delay: 500; Voltage Inhibit: 0.0; 81-4 element mode: Under; PU: 59; Time Delay: 100; Voltage Inhibit: 0.0; 81-5 element mode: Over; PU: 61; Time Delay: 100; Voltage Inhibit: 0.0
87G	13	Generator Phase Differential	BE1-FLEX: Min PU: 0.1 • tap; Tap: I; Slope: 15%	87 element mode: Percent Differential ; Minimum Rest. PU: 0.10; Slope Mode: Maximum Restraint Slope 1: 15; Time Delay: 0
87N	8	Generator Ground Differential	BE1-FLEX: Min PU: 0.1 • tap; Slope 15%; Time delay: 0.1 s; choose low tap	87N element mode: Enabled; Iop Minimum: 1.5A; Time Delay: 50 ms; Overcorrection Coefficient: 1.5; CT Flip: No; Transient Time Delay: 100 ms

(1) See Figure 40 for a screenshot of the BE1-FLEX Protection Summary tab. See Figure 41 for a screenshot of the BE1-FLEX 87 Phase Differential settings screen.

(2) Only settings as applied to the example specifications provided in Table 1 are shown in this column. Settings appearing in BESTCOMS*Plus* but not shown here, are unchanged from their default values except in the case of the 49 element where the source and voting settings depend on prior configuration.

(3) Requires additional configuration before these settings become enabled. Voting may be changed depending on the number of RTDs in each configured group. Source name reflects default labeling. See BE1-FLEX instruction manual for more information.

(4) BESTCOMS*Plus* defaults thermal settings in terms of degrees Fahrenheit. If settings are in terms of degrees Celsius, as in this example, the display units should be changed to metric in “Settings Explorer>General Settings>Display Units” before making settings active.

(5) Elements that compose 50/27 IE must be further configured in BESTlogic™*Plus*. Consult the BE1-FLEX instruction manual for more information on using BESTlogic™*Plus*.

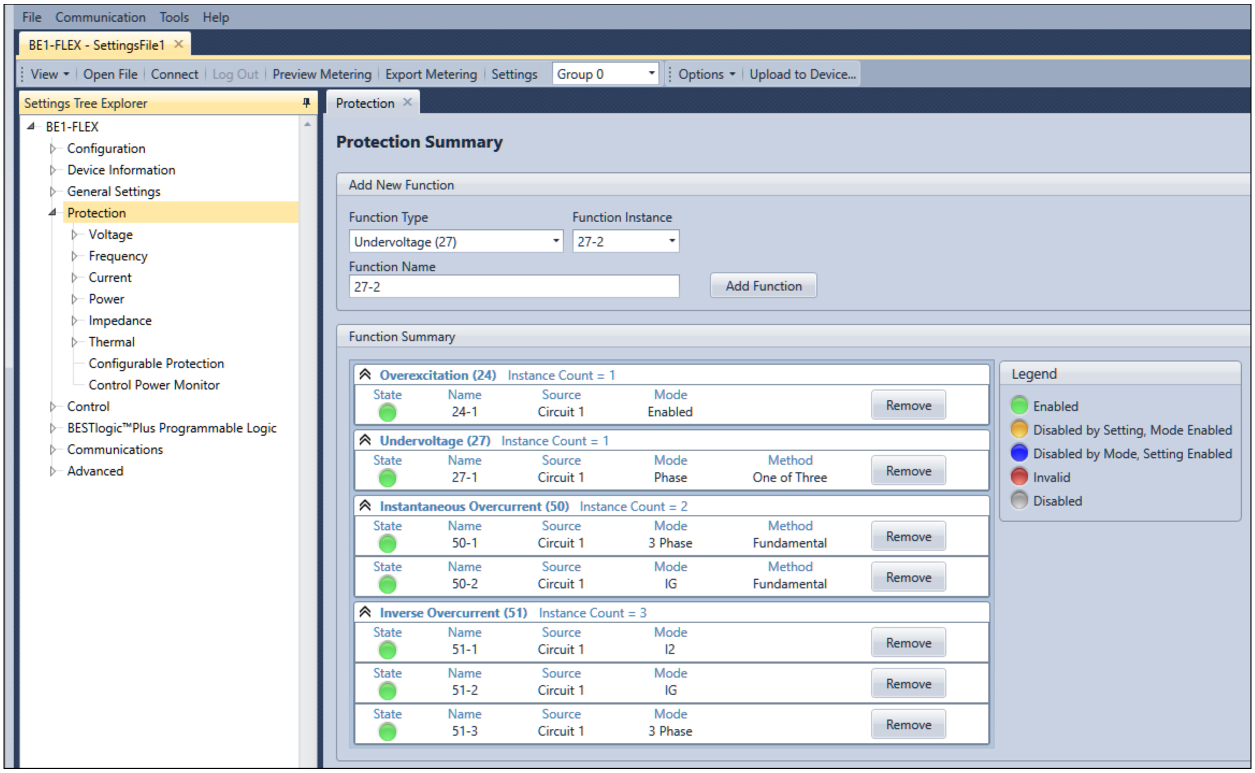


Figure 40. BE1-FLEX Protection Summary Tab in BESTCOMS*Plus*®

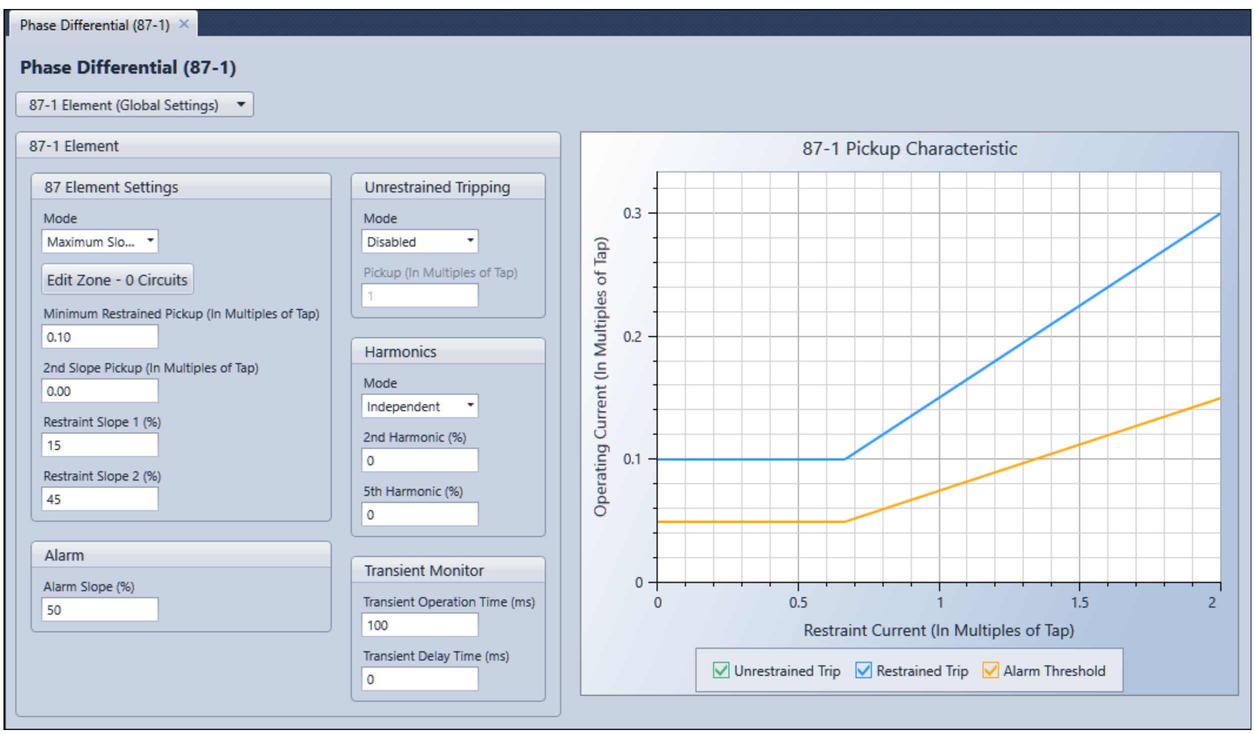


Figure 41. BE1-FLEX Phase Differential (87-1) Settings Screen in BESTCOMS*Plus*®

The BE1-FLEX provides flexible, reliable, and economical protection, control, monitoring, and measurement functions for small, medium, and large generators. Protection package options range from Control Only to All Protection and Control Functions. BE1-FLEX elements commonly applicable to generator protection are highlighted in Figure 42.

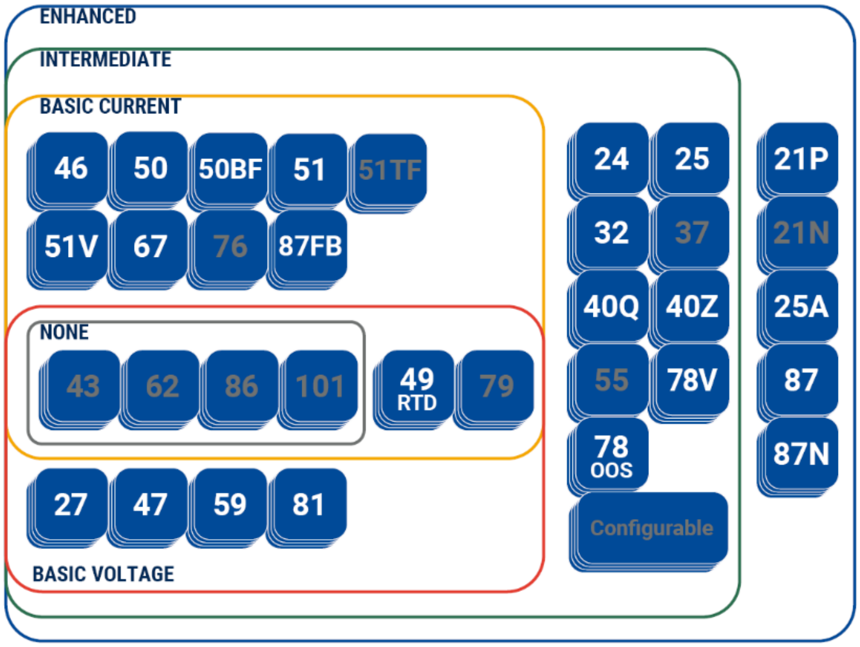


Figure 42. BE1-FLEX Protection Package Options

Notes: The 51 element is used for 51VC and 51VR protection.
A stand-alone BE1-64F relay provides ground fault detection.

To Learn More

To learn more, please email usatechsupport@basler.com or call 618.654.2341 to speak with a Basler representative.

References

1. IEEE C37.101, IEEE Guide for Generator Ground Protection
2. IEEE C37.102, IEEE Guide for AC Generator Protection
3. IEEE C37.106, IEEE Guide for Abnormal Frequency Protection for Generating Plants
4. J. Lewis Blackburn, “Protective Relaying: Principles and Applications”, 2nd Edition, Marcel Dekker, Inc., 1998.
5. S. Horowitz and A. Phadke, “Power System Relaying”, John Wiley & Sons, Inc., 1992.