Protective Relaying of Emergency and Standby Generators

Timothy J. Coyle, P.E.
Member, IEEE
KFI Engineers
Roseville, MN
tjcoyle@kfi-eng.com

***Abstract* – This paper addresses electrical protection of synchronous AC generators used for emergency or standby service, defined as supplying power to critical loads during interruptions of the normal power source. IEEE C37.102 – Guide for AC Generator Protection serves as a comprehensive reference for electrical protection of synchronous generators, but is primarily concerned with large hydraulic, steam and combustion turbine generators. Most emergency and standby generators are small (<5 MVA) and driven by reciprocating engines or small gas turbines. These machines are exposed to application conditions not seen by large generators including step loading and unloading, transformer inrush currents, high sustained short circuit currents, and synchronizing under load. This paper will review some of the protection guidelines of C37.102 and discuss considerations specific to emergency and standby applications.**

***Index Terms* – Power System Protection, Generator Protection, Emergency Power, Standby Power, Mission Critical Power**

I. INTRODUCTION

Synchronous generators commonly used in emergency and standby power systems range in capacity from tens of kVA to several MVA with rated voltages from 208V to 13,800V. They are applied as individual machines serving one or more automatic transfer switches or transfer switchgear and as multiple units operating in parallel on a common bus. Large systems of paralleled units can either serve transfer equipment directly at utilization voltage between 208V and 600Vor supply a medium voltage distribution system serving transformers that step down to utilization voltage and in turn serve transfer equipment. These generators may also parallel with a utility or other on-site generation sources on a short-time basis for the purpose of transferring the load back to normal power without an interruption or on an extended basis for load testing or peak shaving. The terms "emergency" and "standby" are often used interchangeably but do have application distinctions within certain building codes such as [6]. For simplicity, this paper will use the term standby to apply to both.

Electrical protection of low voltage (600V and below) generators in individual service is typically provided by a combination of a molded case or low voltage power circuit breaker at the output terminals and electrical protective functions included in the manufacturer's generator set controller. These units contain the output circuit breaker and the current transformers (CTs) and potential transformers (PTs) necessary for the controller protection as an integral part of the generator set package. This paper does not address this configuration as the circuit breaker and its settings are typically selected by the generator set manufacturer.

Low voltage generators in parallel operation require a high-speed electrically operated switch or circuit breaker for synchronizing and these are typically, though not always, located at separate switchgear. In this case, applying protective relays at the switchgear or use of the electrical protection functions in the generator set controller can allow the unit-mounted output circuit breaker to be eliminated.

Medium voltage generators do not typically include a circuit breaker as part of the generator set package; it and the protective relay(s) are usually located in separate switchgear. The generator set controllers for these packages include electrical protection functions and the current transformers required for the controller are provided, but some units may not include PTs, instead relying on voltage signals from those at the switchgear.

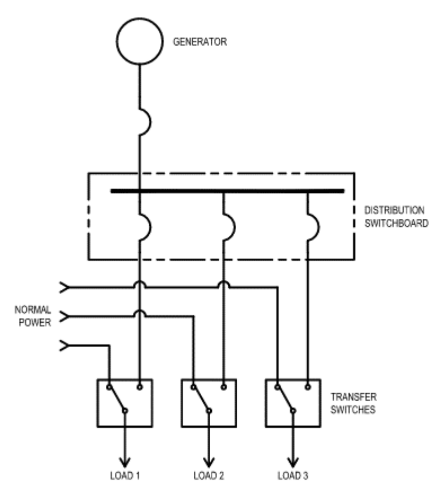


Fig. 1 – Individual Generator Serving Transfer Switches

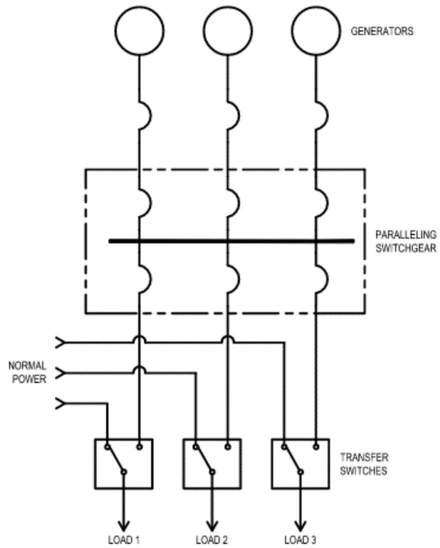


Fig. 2 – Paralleled Generators Serving Transfer Switches

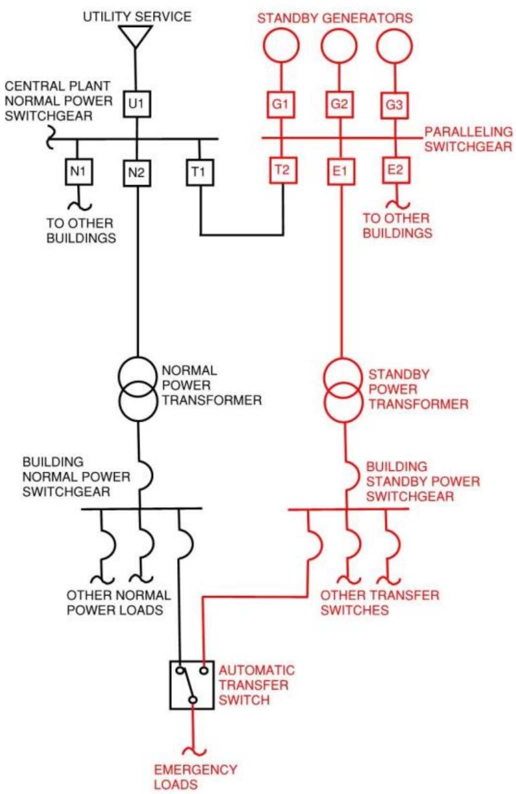


Fig. 3 – Paralleled Generators Serving a Medium Voltage Distribution System

II. UNIQUE CHARACTERISTICS OF EMERGENCY AND STANDBY POWER APPLICATIONS

Step Loading and Load Rejection

Most large generators are placed on-line, gradually loaded, operated at a relatively constant load, and then gradually unloaded before they are taken off-line. Standby generators are subject to step loading and unloading both as they come on- and off-line and during operation. The US standard for emergency and standby power systems requires generators to be capable of assuming and rejecting their rated load in a single step without damage or tripping [7]. Large step changes in loading result in voltage and frequency transients which can last up to several seconds and must be accounted for when setting protection elements that use these quantities.

Transformer Energization

In systems with the configuration shown in Figure 3, it is common for all generators to be started upon loss of normal power. The circuit breaker for the first unit to reach acceptable voltage and frequency is closed to energize the bus, the remaining units synchronized, and their generator breakers closed. Transformers supplied by the generation bus are normally energized simultaneously by the first generator alone because they serve loads that are required to have power restored in a shorter time frame than required to synchronize multiple generators to each other.

This sequence of operations leads to a single unit providing magnetizing inrush current to transformers, the sum of whose kVA ratings may be many times that of the generator rating. This high current results in an instantaneous voltage dip with gradual recovery to normal voltage and load current as the magnetic fields in the transformers build up. Protection elements that operate on voltage or current may be susceptible to false tripping during this period.

Excitation Support

The generator(s) in a standby power system usually represent a weaker source of fault current than the normal power source which can lead to delayed tripping or clearing times for the overcurrent protection devices in the distribution system. Many systems are required by code to be selectively coordinated, which requires that the available fault current be adequate to clear downstream faults before the generator thermal and mechanical limits are reached requiring it to be tripped.

To support operation of downstream overcurrent protection, the excitation systems of standby generators are designed to sustain short circuit currents of 2.5 to 3.0 PU for up to 10 seconds. This does not affect the portions of the short circuit current decrement characteristic that are determined by the sub-transient and transient reactances and time constants, but the vertical section of the curve that would normally be determined by the synchronous reactance is shifted to the higher value of sustained current as indicated in Figure 4. The generator short circuit thermal damage time limit of 30 seconds without excitation support ($I_{SC} = 1/X_d$ PU) is reduced to 10 seconds at the higher sustained current.

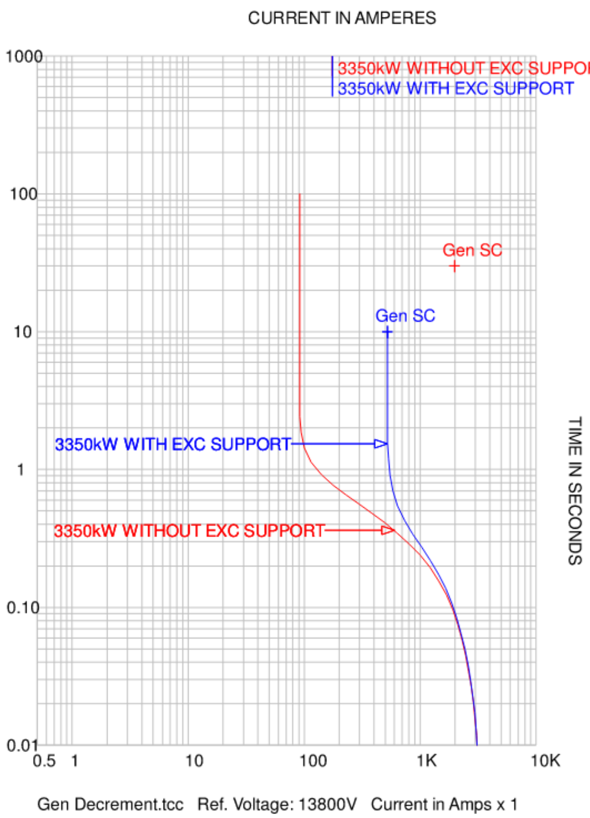


Fig. 4 – Adjusted Generator Short Circuit Characteristic

When plotting the generator decrement characteristic from power system modeling software, it is important that the appropriate adjustments to account for excitation support are made. A characteristic based strictly on machine reactances and time constants will be inaccurate for that portion of the curve where most downstream devices will operate.

Synchronizing Under Dynamic Conditions

Most guidelines for synchronizing generators are based on the unit being gradually brought up to synchronous speed against an infinite bus and the voltage and frequency being adjusted until the acceptable window for breaker closure is achieved. There is rarely any urgency to close the breaker and practice errs on the side of protecting the machine from the mechanical and electrical transients associated with synchronizing in too wide a window.

When multiple generators are paralleled in a standby power system it is usually because more than one unit is required to serve the load and, after the most critical loads are re-energized by the first unit on the bus, transfer of additional blocks of load may be delayed until additional generators are synchronized and connected. Synchronizing of incoming generators to the running bus is desired to occur within seconds, not minutes, to speed the restoration of power to these other loads.

Synchronization may be complicated by the fact that the incoming generator is not coming up to speed gradually, but ramping from rest to rated RPM in seconds, possibly with significant overshoot of voltage and/or frequency. Also, the load on the on-line generator(s) may be variable, leading to variation of bus voltage or frequency during the synchronization period – essentially creating a “moving target” for the synchronizer.

II. GENERATOR SET CONTROLS

Microprocessor-based controls provided as an integral part of the engine-generator package now contain some of the same electrical protection functions previously provided only by protective relays. On a recent project in which no on-board protection was specified, the standard engine controls proposed by three bidders contained the protective functions shown in Table I.

TABLE I. On-Board Generator Protection Features

PROTECTION FUNCTION	**BRAND**		
	A	**B**	**C**
Undervoltage (27)	X	X	X
Reverse Real Power (32 - kW)	X	X	X
Reverse Reactive Power (32 – kVAR)	X	X	
Loss of Excitation (40)			X
Current Unbalance (46)	X		
Phase Sequence (47)	X		X
Thermal Overload (49)	X	X	
Stator Overcurrent (50/51)	X	X	X
Field Overcurrent (51F)		X	
Overvoltage (59)	X	X	X
Under/Over Frequency (81O/U)	X	X	X

If enabled, these functions must be considered in developing the overall protection scheme for the generator and in coordination with system protection. They may be used in lieu of providing an external generator protection relay or employed along with external relaying as redundant protection. It is the author’s practice in most cases to use external relaying for primary protection and the on-board features as backup for the following reasons:

- They may not include all the required or desired protection functions.
- Program access and ability to adjust settings may be limited to the manufacturer’s service technicians.

- In the event of a trip, protective relays may provide more extensive diagnostic information including sequence of events reports and COMTRADE files that can be analyzed without proprietary software.

III. GENERATOR PROTECTIVE RELAY FUNCTIONS

General

The basic principles to be applied in selecting protective relay functions and settings for standby generators start with those applied in any other power system application:

- Protect equipment and conductors from mechanical and thermal damage.
- Minimize the extent of damage at the point of the fault.
- Trip selectively to remove from service only the faulted portion of the system.
- Provide backup protection in the event of relay or circuit breaker failure.
- Accommodate normal system operating conditions without tripping.

Much guidance for selecting protective relay functions and settings for these units can be found in the classical references that power engineers have used for years [1] [2] [3], as well as more current publications. However, consideration must be given to the differences between the operating characteristics and controls of reciprocating engine-generators and those of the turbomachinery on which most references are based as well as the application considerations discussed in Section I.

Protection settings must accommodate anticipated transients without tripping, yet clear fault conditions quickly enough to maintain system stability and preserve the generator bus to serve the standby load. We have observed installations in which relay settings based on traditional guidelines for generator protection failed to meet these criteria, resulting in false tripping or, in the extreme, inability of the standby plant to assume the load.

This discussion presumes the use of a microprocessor-based multifunction Generator Protection Relay (GPR) and the typical arrangement of PTs and CTs shown in Figure 5.

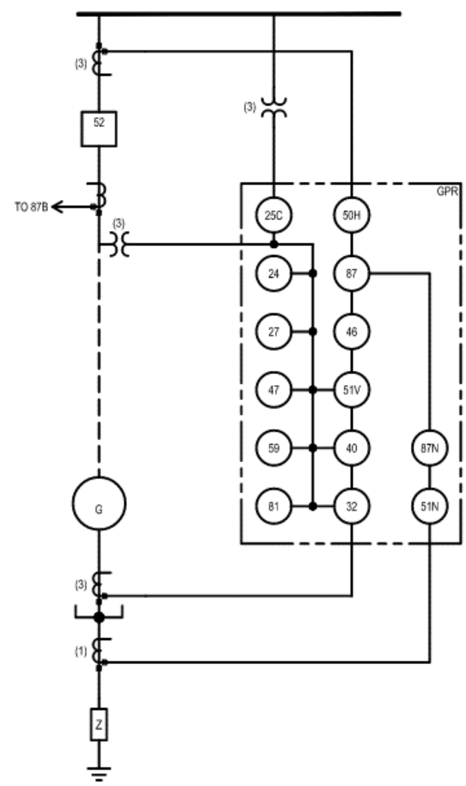


Fig. 5 – Protection Single Line Diagram

Stator Thermal Protection

Stator thermal protection can be provided by time overcurrent elements selected to coordinate with the manufacturer's thermal damage curve or by resistance temperature detectors (RTDs) embedded in the stator windings. The former provides protection against overloads, but the alternators on standby machines are rarely subject to overload due to the limited mechanical power output of the prime mover and a load power factor that usually exceeds the nameplate value. For this reason, RTDs, which can detect winding temperature rise due to any cause including overload, blocked ventilation openings, or high engine room temperature, are preferred.

Because of intermittent duty, alternators with standby ratings are permitted higher temperature rise for a given insulation class than those designed for continuous duty [5], and this must be accounted for in selecting alarm and trip settings. Absent specific recommendations from the manufacturer, Table 2 provides settings based on standby operation at a 40 C ambient temperature with the alarm set at the insulation total temperature rating and the trip set 10 degrees higher. For critical applications with qualified operators, it may be desirable to alarm without tripping to allow for intervention to correct the problem.

TABLE II. Stator RTD Alarm and Trip Temperatures

CLASS	TEMP RISE	ALARM	TRIP
A	85 C	125 C	135 C
B	105 C	145 C	155 C
F	130 C	170 C	180 C
H	150 C	190 C	200 C

Stator Fault Protection

Stator fault protection of standby generators should be provided in the same manner as for other units. GPRs offer options for full differential protection (87G) and ground differential protection (87GN) as primary stator fault protection. Third harmonic ground undervoltage (27TN) elements for 100% stator ground fault protection are available but the varying nature of the load on a standby machine may make this function impractical.

Differential protection uses the traditional percentage-restrained characteristic shown in Figure 6 with most relays offering the ability to set dual slopes allowing for greater sensitivity at low fault currents while accommodating false differential current due to CT inaccuracy or saturation at high fault currents.

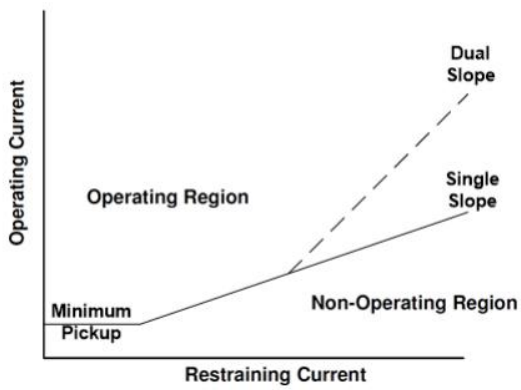


Fig. 6 – Percentage Differential Characteristic

False tripping due to CT saturation for out-of-zone faults and transformer inrush current is a common problem in differential protection of small generators for two reasons:

1. Rated current of medium voltage standby generators is typically less than 200A and CTs selected to meter accurately at this level tend to have low saturation voltage ratings.
2. The traditional approach of providing the same model and rating of CTs at the generator neutral terminals and in the switchgear is often impractical due to space constraints in the terminal box and generator set manufacturers' standardized designs.

Figure 7 shows a portion of the current waveforms from a 2000kW, 13.8kV emergency generator picking up transformer inrush current from 3250 kVA of connected step-down transformers. In this case, a 600:5A multi-ratio CT in the switchgear which was tapped at 150:5 to serve both the GPR and metering saturated, leading to a false differential trip on B-phase. The accuracy class of the CTs at that tap is C20, compared to the C100 accuracy at the 600:5 ratio.

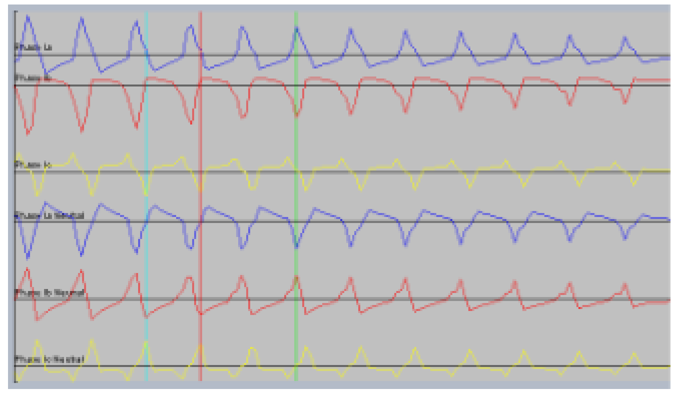


Fig. 7 – Transformer Inrush Current Waveforms

Relaying CTs should be specified with ratios and accuracy classes suitable for the application as described in [4] and separate CTs should be provided for metering and control circuits if a lower ratio is required for low-current metering accuracy. If adequate accuracy cannot be obtained there are two options to allow differential protection to be retained:

1. Increase the percentage slope setting and/or add time delay to accommodate the error current for the expected duration of the external fault or inrush transient.
2. Utilize a CT saturation detection algorithm in the protective relay. Different manufacturers have different approaches, with criteria such as pre-saturation current direction, the sequence in which restraint and operating currents increase, etc. In all cases, though, they work to determine whether an increase in differential current is due to CT saturation or an in-zone fault and block or release the 87 element accordingly [8] [9].

The original settings for the 87 element of the relay with the current waveforms of Figure 7 were:

- Pickup: 0.14 x CT (21A)
- Slope 1: 10%
- Breakpoint: 2 x CT (300A)
- Slope 2: 20%

The relay manufacturer was able to bench-test a similar relay with the currents recorded in the event report COMTRADE file and reported that increasing Slope 1 to 20% would still not make the relay secure against this transient and a time delay of

5 cycles should be added to the trip logic. The facility operator did not want to defeat the high-speed protection for internal faults, so elected instead to replace the relay with a newer model having a CT saturation detection feature.

Backup Protection

Backup protection for stator faults is available from the same functions providing backup protection for system faults. Available elements include phase distance (21), voltage-restrained or voltage-controlled overcurrent (51V), and either neutral overcurrent (51N) or neutral overvoltage (59N), depending on the neutral grounding configuration. These functions must be provided with enough time delay to allow system faults to be cleared by feeder protection and avoid mis-operation under transformer inrush conditions.

Distance elements are rarely used because most systems have short line lengths and do not use distance protection elsewhere, making selectivity difficult. Both 51V and 51N elements should be set based on graphical analysis of time-current-characteristic (TCC) plots that include both the downstream feeder protection relay curves and the generator short circuit current decrement characteristic.

High speed backup protection for high current internal faults is recommended if the source the generator parallels with has significantly higher short circuit capacity than the machine. This scheme utilizes a high-set instantaneous overcurrent element (50H) in the CT circuit on the bus side of the differential zone. Setting this element above the maximum short circuit current the generator can contribute to a bus fault (($I_{SC} = 1/X_d''$ PU) assures that it will not interfere with selective clearing of downstream faults but will operate for a high reverse current feeding into a fault in the generator zone from the parallel source.

Breaker Failure Protection

Breaker failure protection should be considered for all standby generators that parallel with other units or a utility source to prevent severe damage from sustained current for faults in the generator zone. Standby generator circuit breakers are operated frequently for testing and thus may be more susceptible than other medium voltage circuit breakers to mechanism failures. Large or continuous duty generators are often provided with redundant protective relays, lockout relays, and trip coils, but economy leads to most standby generator circuit breakers relying on a single trip circuit and trip coil.

The breaker failure scheme must disconnect all sources that can supply the generator bus. If bus differential protection is provided, this can be accomplished by wiring the breaker failure output of the GPR to trip the bus lockout relay.

Field Circuit Protection

Most emergency/standby generators use brushless rotating exciters in which, rather than controlling field current directly, the voltage regulator controls the stationary field of a shaft-mounted 3-phase alternator, the output voltage of which is rectified by shaft-mounted diodes and applied to the field winding. Field circuit protection is typically a function of the voltage regulator or other excitation system components and not of the generator protection relay.

Loss of Excitation

Figure 8 depicts traditional dual impedance element protection for loss of excitation with the standard offset and diameter settings. Circle 1 is used with little or no time delay to cause tripping before the unit can drop out of step and Circle 2 with a delay of approximately 0.5 seconds to accommodate transients. The leading portion of the reactive capability curve (Figure 9) of the same standby generator is translated to the impedance diagram showing that these settings generally allow operation up to and slightly beyond the machine limit.

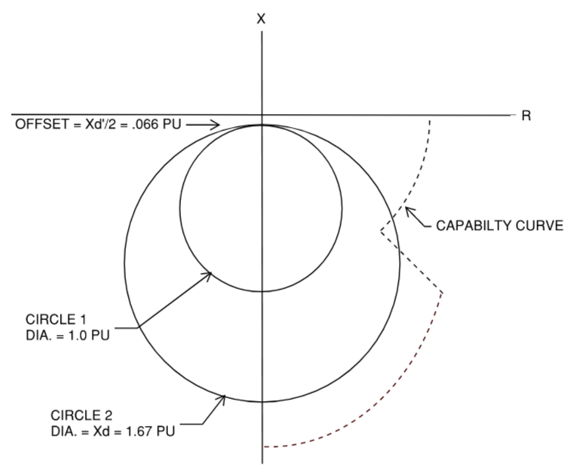


Fig. 8 - Loss of Excitation Impedance Plot

Standby generators, however, are never operated intentionally absorbing VARs and an impedance characteristic that falls outside the permissible area of the capability curve may not coordinate with on-board reverse VAR settings that fall inside the capability curve. A simpler approach that can be considered is a single reverse kVAR setpoint at 95 percent of the minimum negative kVAR value of the curve, as shown in Figure 9. A reverse VAR setpoint with a pickup and time delay chosen to coordinate with on-board protection may also be combined with a single impedance element set as Circle 1 to provide fast tripping for complete loss of excitation.

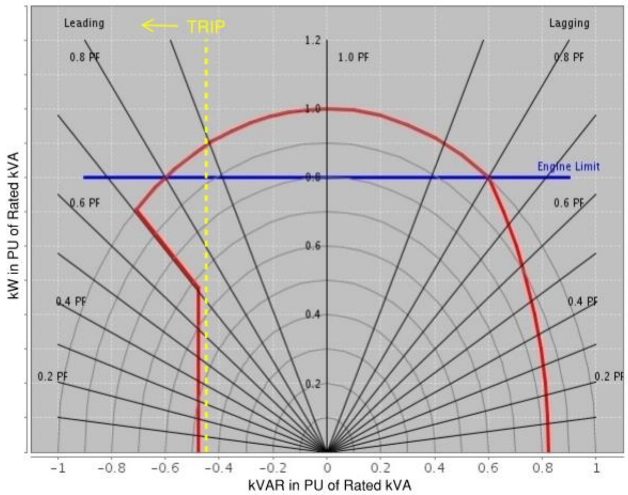


Fig 9. Reactive Capability Curve with Reverse kVAR Setpoint

Unbalanced Current

Unbalanced current in standby machines can be introduced by unbalanced load, by parallel operation with a stronger source having unbalanced voltage (we have observed this in parallel operation with a utility having single-phase voltage regulators fall out of step with each other), or by unbalanced system or generator faults. In the last case, it is expected that other protection elements would clear the unbalanced condition promptly.

In the case of sustained unbalanced current, protection using an $i_2^2t = K$ characteristic as discussed in [2] is appropriate. Unless specified differently on manufacturer's data sheets, a pickup setting of 0.10 PU and a value of K = 40 PU^2-seconds are appropriate for standby generators based on their salient pole construction.

Overexcitation (Volts per Hertz)

Problems with the prime mover governor may result in operation at normal voltage but reduced frequency, causing over-excitation that is not detected by overvoltage protection. Damage from this condition is thermal and therefore time delay adequate to accommodate transients as discussed in [2] is recommended.

Reverse Power (Motoring)

Reverse power protection is necessary only for units that parallel with another source. Settings normally used with steam or hydraulic turbines are far more sensitive than necessary for the prime movers used with standby generators and may result in nuisance tripping.

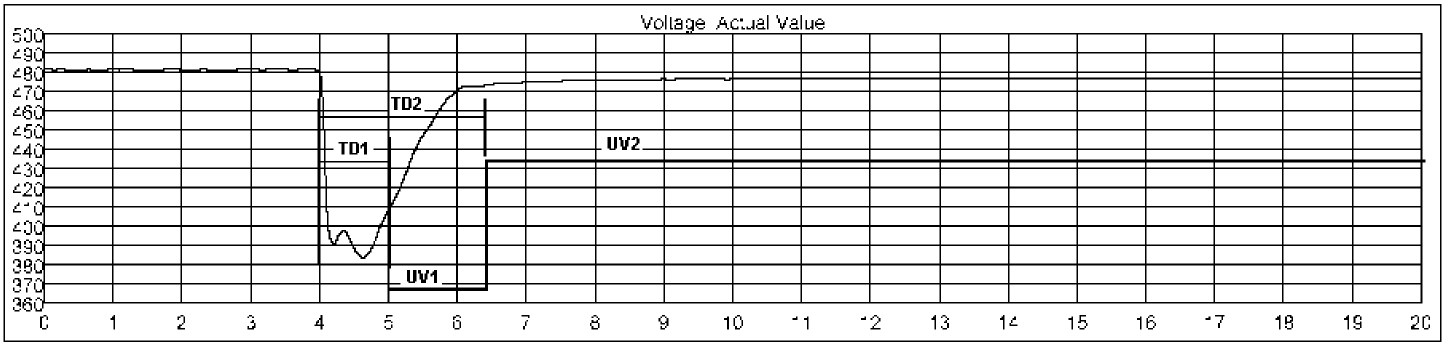
Diesel engines and gas turbines require 25 percent and 50 percent respectively [1] of rated power when motored without a fuel supply due to the work of compression. A reasonable pickup setting is 50 percent of this value with a practical lower limit established by how well the load sharing controls function when multiple units operate in parallel with no net load and during loading transients. Sufficient time delay, usually in the range of 10 to 15 seconds, is required to avoid tripping during synchronizing transients.

Protection against motoring in the event of a manual shutdown or mechanical trip of the prime mover can be provided by wiring a normally closed contact on an "engine running" relay at the generator set controls to directly trip the generator circuit breaker when the engine shuts down.

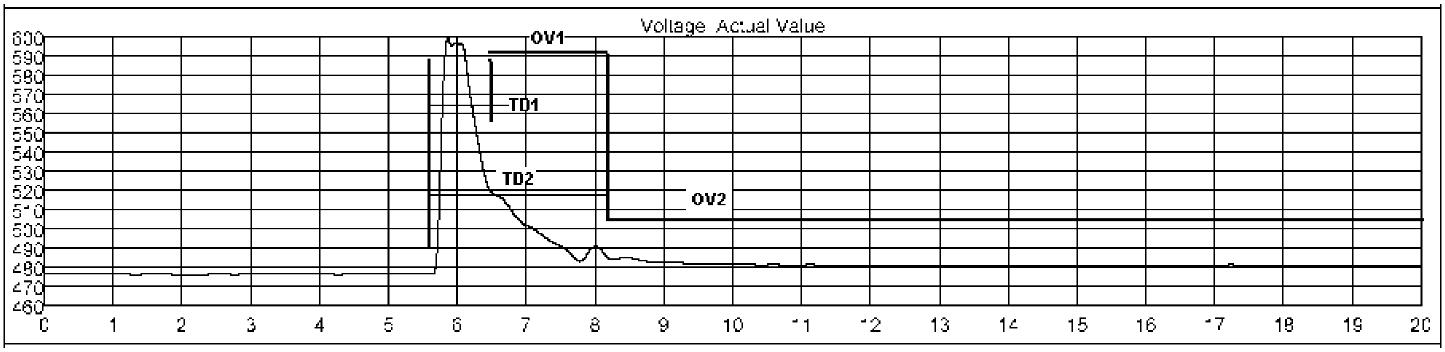
Voltage and Frequency Protection

Applying voltage and frequency protection to standby machines requires knowledge of the transients that may occur during step loading and step load rejection and awareness that the machine damage criteria that are behind the recommendations for frequency protection for turbine-driven machines do not apply to engine-driven units. Overvoltage (59) and over-excitation or volts per hertz (24) are the only elements required for protection of the generator itself. Undervoltage (27) and over/under frequency (81O/U) elements may be used in backup protection schemes or to protect the load from sustained operation at abnormal conditions due to a failed governor or voltage regulator but are not required from a generator protection standpoint.

Voltage and frequency elements, if used, must be set to accommodate the worst-case loading transients that may occur without tripping the generator. These transients can be predicted by the generator manufacturer using stability analysis or can be recorded during factory testing or commissioning using oscillography. In either case, some margin for deteriorating performance of controls over time should be included in determining settings.



(a)



(b)

Fig. 10 - Generator Voltage Transients and Relay Characteristics

Figure 10(a) depicts an actual measured voltage transient produced by 100 percent block loading of a 2000 kW, 1800 RPM, diesel-engine generator with a two-step undervoltage relaying scheme that can be used to accommodate such a transient. Undervoltage element UV1 is set to pick up at a voltage safely below the minimum voltage experienced during the transient and a time delay T1, that will coordinate with downstream relaying to avoid tripping the generator for voltage dips associated with system faults. The second undervoltage element UV2, is set just below the minimum acceptable continuous operating voltage of the load, with a time delay T2, adequate to ride through the loading transient. A similar scheme can be applied to overvoltage protection, as shown on the voltage transient recorded for the same machine during 100 percent load rejection (Figure 10b), although in this case, T1 need not consider downstream coordination but should include several cycles of delay to ride through system voltage transients of other origins.

Similar logic can be applied to selecting frequency settings with respect to the expected worst-case frequency transients under block loading and load rejection conditions. In this case, the time delays selected for the first step of both under-frequency and over-frequency elements should be coordinated with downstream fault protection relays. Generator frequency under fault conditions may drop or rise, depending on the nature of the fault (arcing vs. bolted), the pre-fault load and the governor response.

It should also be noted that in systems where multiple machines are paralleled on a common bus, the control system usually monitors bus voltage and frequency and has provisions to shed load in one or more steps should that become necessary; generator relay settings must also be coordinated with the setpoints and time delays used in the load shed scheme to avoid tripping a generator unnecessarily.

Inadvertent Energization

Most GPRs offer an algorithm to protect against inadvertent energization of a stationary machine through circuit breaker closure or flashover. While there are different schemes in use, in general the logic uses the fact that current increases from zero without a prior increase in generator terminal voltage and issues a high-speed trip command. This will re-open the generator circuit breaker (inadvertent close) or initiate breaker failure tripping (flashover) much faster than the standard protection elements that would otherwise come into play in this situation. This function is highly recommended for standby systems, in which complex switching schemes and the use of circuit breakers that are capable of manual as well as electrical closing increase the chances of inadvertent energization through human error.

The prime mover running interlock described in the paragraph on reverse power protection can also help protect against inadvertent breaker closure.

IV. SYNCHRONISM CHECK

Synchronism-check relay elements are intended to verify that the generator is within acceptable ranges of voltage, frequency, and phase angle with respect to the bus before permitting a breaker closure. They typically drive a normally open output contact in the circuit breaker close circuit that closes when the programmed conditions are satisfied. They are always used to supervise manual synchronizing of the generator and should also supervise the automatic synchronizer.

Synchronism-check elements generally permit setting of the following parameters:

- Generator voltage window
- Voltage difference between generator and bus
- Frequency difference (slip) between generator and bus
- Maximum phase angle difference
- Breaker closing time (anticipation)

Synchronism criteria typically used for large generators [2] are:

- Less than 5% voltage difference
- Maximum 0.067 Hz slip frequency
- Maximum 10 degrees phase angle difference

Both the slip frequency and voltage difference may be required to be positive (generator with respect to bus) to assure that initial real and reactive power flows on circuit breaker closure are toward the system.

Applying these settings to standby generators may result in delayed or failed synchronization for the reasons described in Section I of this paper, but it is difficult to find alternate criteria for standby generators. One engine-generator manufacturer provided the following limits for synchronizing to limit transient current to within 1.5 PU, assuming an infinite utility bus:

- Voltage: 1 percent
- Phase Angle: +/- 10 Degrees
- Slip Frequency: 1 percent (.6 HZ)

While this provides a more lenient slip frequency, the voltage matching criteria may be beyond the capability of some automatic synchronizers and less than the combined measurement accuracy of potential transformers and protective relays.

It is often desirable to get all the generators operating in parallel on the standby bus as soon as possible following the loss of utility power because automatic controls are arranged to manage the load on the system by adding pre-set blocks of load in a set priority order as each generator circuit breaker closes. To speed this process, voltage matching capability may not be provided on generator synchronizers; modern voltage regulators have relatively little drift, and absent manual intervention, generator voltage setpoints are highly likely to remain reasonably close to one another.

However, if the system synchronizes the entire generator bus to the utility source for restoration this almost always requires voltage matching due to the wide variation possible in the utility supply voltage. This seeming conflict can be resolved, and reliability maximized, by providing a dedicated synchronizer and appropriate synchronism-check settings in the GPR for each generator and a separate system synchronizer and synchronism-check settings for the intertie breaker(s).

Maximum slip frequency settings may need to be determined by trial and error during commissioning, balancing the conflicting goals of minimizing transient power flows and the time required to synchronize the unit. It is recommended that both positive and negative slip be permitted. This avoids a failure to synchronize condition that can occur if bus frequency is higher than nominal and positive slip is required by the synchronism-check settings but not by the automatic synchronizer.

V. CONCLUSION

While standard industry references provide excellent guidance for selecting and setting many of the protective relay functions for standby generators, application conditions unique to these systems must be considered in deciding whether to use certain functions, and if so, how to set them. Special attention must be paid to transient conditions such as step loading and unloading and high transformer inrush currents to assure they do not cause false tripping. Prime mover characteristics that differ from those of large turbomachinery must also be accounted for. If these considerations are properly addressed, relay settings can be developed that provide a high degree of protection of the alternator without compromising system reliability.

REFERENCES

[1] Applied Protective Relaying, Westinghouse Electric Corporation, Coral Gables, Florida

[2] ANSI/IEEE C37.102 - Guide to AC Generator Protection

[3] ANSI/IEEE C37.101 – Guide to Generator Ground Protection

[4] IEEE C37.110 - Guide for Application of Current Transformers Used for Protective Relaying Purposes

[5] NEMA MG1 – Motors and Generators, National Electrical Manufacturer's Association.

[6] NFPA 70 – National Electrical Code, National Fire Protection Association

[7] NFPA 110 – Standard for Emergency and Standby Power Systems, National Fire Protection Association.

[8] Donolo, Marcos, et.al., Generator Protection Overcomes Current Transformer Limitations, 41st Annual Western Protective Relay Conference, Spokane, WA, October 14-16, 2014.

[9] Xu, Zhihan, et. al., CT Saturation Tolerance for 87L Applications, IEEE 86th Annual Conference for Protective Relay Engineers, March-April, 2015

[10] Thompson, Michael J., Fundamentals and Advancements in Generator Synchronizing Systems, Texas A&M Conference for Protective Relay Engineers, 2012