Power Generation

Application Engineering

T-016: Paralleling Application Manual

English
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1 Introduction

1.1 Overview

Much has been written about pervasiveness of technology in the world. Even in developing countries, electrical equipment of all sorts, ranging from convenience devices like air conditioning and television to protection and preservation of life, like hospital equipment, is more and more common. Power demand in more developed countries, rather than stabilizing, is growing, and the patience of the populace for “life without power”, even for a short period of time, is dwindling, requiring more and more entities to invest in on-site power generation equipment. With the ever-increasing demands for power come general trends that are driving the use of more and more applications where generator sets are paralleled to provide the power system capacity and reliability that customers need and want.

It has long been recognized that paralleling of generator sets can be a valuable tool in the drive to improve power system reliability in critical installations. Use of multiple generator sets capable of serving a common load is often considered to be more reliable than single level backup and support systems. So, for applications that depend on power for life safety, and applications that depend on power to assure the financial viability of a business, paralleling is often considered to increase the probability that critical loads are served.

Paralleling is also common in applications where there is no normal utility-supplied power, such as in remote communities where extension of a utility-based transmission system is not practical and in applications where power is needed only on a relatively temporary basis. In these cases the function of paralleling is the same, but the system designs are somewhat different in that they typically do not use load sequencing functions and there is a greater concern for minimizing fuel consumption and protecting the equipment for the long run. These applications are common in remote areas of Canada, many areas of South America, outback Australia, the Pacific islands, and Africa. Even in more populated areas, they may be used for mining applications, new building projects, or as part of the upgrade of existing facilities. Often these applications utilize rental generators rather than customer-owned equipment.

Beyond these emergency/standby and prime power-driven needs, automatic paralleling is often employed as a means to improve the utility/mains power distribution system or provide temporary solutions to capacity constraints in utility distribution systems. Small diesel generator sets are not particularly efficient equipment for prime power applications compared to traditional utility service equipment that is many times larger. However, small generator sets rated up to about 2500kW and employed in systems as large as 20MW or more can provide valuable service in providing temporary relief to overloaded distribution grids whether that overload is due to capacity constraints or distribution equipment constraints. In this application, as the “Smart Grid” develops, it is likely that synchronous paralleled generation will play a significant role due to the ability of the equipment to quickly start and drive power into the system.

Whatever the application, when expanded on site capacity is needed, or reliability enhancement is desired, paralleling is a tool that can be used to meet system goals and requirements.

1.2 About This Manual

The purpose of this manual is to provide information on the functions, requirements, and operation of paralleling equipment in an onsite power system. It is also intended to provide guidance in the design of applications and the selection of equipment for specific applications where paralleling is desired.

Chapter 2 briefly covers what paralleling is and why it is a useful practice in many applications. The introduction also reviews specific applications that are less attractive for paralleling, and some of the risks associated with paralleling applications. Finally, the introduction covers the principles of paralleling that drive system requirements, performance, and capabilities; and the general configuration of the system equipment that provides necessary functions.

Chapter 3 covers the control functions necessary to parallel generator sets in detail. It covers first the functions that must be provided, and then addresses equipment that can be used to provide these functions. Similarly, the section also covers master control systems, and power transfer control systems.

Chapter 4 covers power carrying equipment that is used in paralleling applications world-wide. This includes descriptions of necessary paralleling breakers, switchboard and switchgear designs, equipment ratings and variations that may be seen based on local rules.

Chapter 5 describes system design considerations including system topologies, load division and load and capacity management, sizing of generator set and descriptions of common one-line electrical designs, their advantages and disadvantages, typical uses and operational sequences. This section also describes mechanical considerations such as physical location and isolation of equipment

Chapter 6 covers system failure modes, and what provisions can be instilled in a system to minimize the effect of common failures. Concepts of design for enhanced reliability are discussed and reviewed. Protection of equipment, system, and loads is discussed.

Chapter 7 covers special topics, such as dealing with paralleling of dissimilar and potentially incompatible machines, grounding (earthing) of paralleling systems, and special concerns associated with utility paralleling.

The **Appendix** includes information on system validation, installation, commissioning, operation, maintenance concerns, and a glossary.

1.3 About Requirements and Recommendations

Each section of this manual begins with a Requirements and Recommendations section. This material is designed to highlight major points that the designer should consider when working on power systems that include paralleled generator sets.

The requirements information includes critical things that must be done to provide for a safe and reliable facility or to meet generally required codes and standards.

The recommendations information includes major points for consideration to improve reliability or cost in a facility design.

1.4 Application Manuals

Every standby generator set installation will require power transfer equipment, either transfer switches or paralleling switchgear. The proper system for the job and its proper application are crucial to reliable and safe operation. The following Cummins Power Generation application manuals address related aspects of standby and emergency power systems. Because these manuals cover aspects requiring decisions that must be taken into consideration early in the design process, they should be reviewed along with this manual.

Application Manual T-011 - Automatic Transfer Switches. Many applications utilize multiple power sources to enhance electric power system reliability. These often include both utility (mains) service and generator set service to critical loads. T-011 covers the various types of power transfer systems available and considerations for their use and application. Careful consideration of the power switching system at the start of a project will enable a designer to offer the most economically viable and most reliable service to the facility user.

Application Manual T-016 - Paralleling and Paralleling Switch Gear. Paralleling equipment makes two or more generator sets perform as one large set. This can be economically advantageous, especially when the total load is greater than 1000 kW. The decision whether to parallel sets must be made in the early stages of design, especially if space and the need for future expansion are critical factors.

Application Manual T030 – Liquid Cooled Generator Sets. Generator sets may operate as prime power sources or provide emergency power in the event of utility power failure. They may also be used to reduce the cost of electricity where the local utility rate structure and policy make that a viable option. Because of their important role, generator sets must be specified and applied in such a way as to provide reliable electrical power of the quality and capacity required. T-030 provides guidance to system and facility designers in the selection of appropriate equipment for a specific facility, and the design of the facility, so that these common system needs are fulfilled.

Application Manual T-034 -Networking. Communication networks have long been used to make equipment and processes operate more reliably and efficiently. As power generation systems migrate from centralized to distributed generation and control, the communications infrastructure will need to become more comprehensive and standardized so that equipment from multiple suppliers will be able to communicate with each other seamlessly. The purpose of this Application Manual is to educate engineers, system integrators, distributors, and interested users in the fundamentals of networks, as they apply and are used in on-site power generation systems.

1.5 Safety

Safety should be a primary concern of the facility design engineer. Safety involves two aspects: safe operation of the generator set itself (and its accessories) and reliable operation of the system. Reliable operation of the system is related to safety because equipment affecting life and health is often dependent on the generator set – such as hospital life-support systems, emergency egress lighting, building ventilators, elevators, fire pumps, security and communications.

Refer to the Codes and Standards section in the Appendix for information on applicable electrical and fire codes around the world. Standards, and the codes that reference them, are periodically updated, requiring continual review. Compliance with all applicable codes is the responsibility of the facility design engineer. For example, some areas may require a certificate-of-need, zoning permit, building permit or other site-specific certificate. Be sure to check with all local governmental authorities early in the planning process.

NOTE: **While the information in this and related manuals is intended to be accurate and useful, there is no substitute for the judgment of a skilled, experienced facility design professional. Each end user must determine whether the selected generator set and emergency/standby system is proper for the application.**

2 Paralleling Basics

2.1 Overview

This section covers what paralleling is and why it is a useful practice in many applications. The introduction also reviews specific applications that are less attractive for paralleling and some of the risks associated with paralleling applications. Finally, the introduction covers the principles of paralleling that drive system requirements, performance, and capabilities; and the general configuration of the system equipment that provides necessary functions.

2.2 Requirements and Recommendations

2.2.1 Requirements

- To achieve greater system reliability with paralleling for most emergency standby applications, the designer must include provisions for load management. If load management is not possible, reliability can be improved by providing redundant generator sets. Redundancy allows higher reliability of service to lower priority loads by providing more on-line capacity in the system.
- Region specific codes/standards may require an alternate source of standby power to be available whenever the permanently installed emergency generator is out of service for maintenance or repair.
- All the paralleling systems have the basic building blocks of generator sets, paralleling controls, master controls, power transfer controls and power sections.

2.2.2 Recommendations

- Paralleling is commonly recommended in applications that require higher reliability than can be achieved with an individual machine.
- The incremental cost of paralleling can be minimized by carefully considering the degree of redundancy needed in the system.
- Paralleled generators provide higher reliability and greater system bus capacity leading to better performance, service convenience, and in some applications, cost savings.
- When multiple machines are operating in parallel the voltage on the common bus between them must be constant, and frequency and phase sequence of the two are identical at all times.
- Attempts to change voltage and frequency of generators operating in parallel will cause load change rather than voltage or frequency change

2.3 What is Paralleling and Why do You do it?

Paralleling is the synchronous operation of two or more generator sets connected together on a common bus in order to provide power to a common load (see figure below). Paralleling equipment makes two or more generator sets function as if they were one large set. The capacities of the individual equipment directly add together while maintaining nominal bus frequency and voltage.

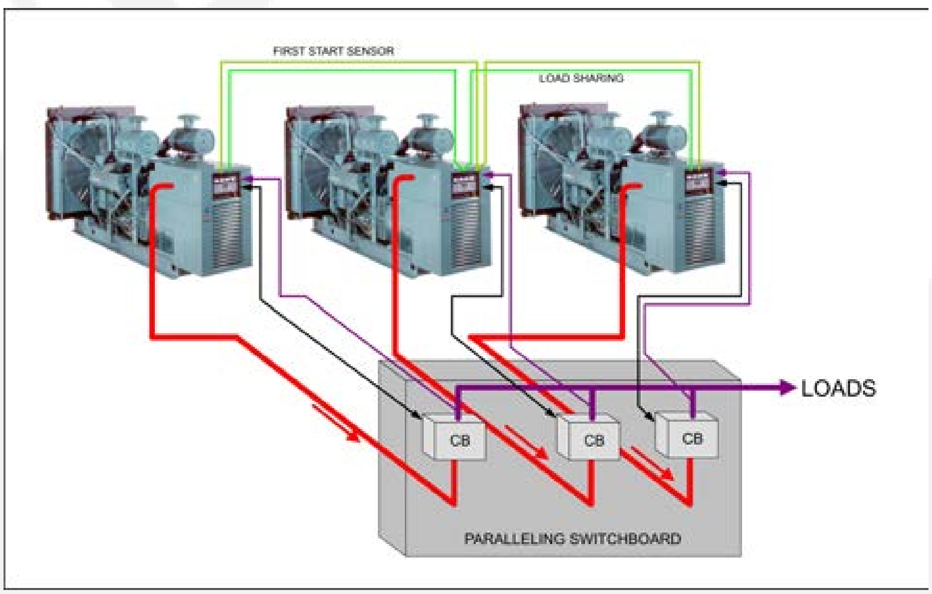

FIGURE 1. PARALLELED GENERATOR SETS CONNECTED TO COMMON BUS, SIMULTANEOUSLY SERVING COMMON LOADS

In the table below, the three generator sets in parallel will perform as one large set, with a combined performance rating equal to the sum of the three individual sets of ratings.

TABLE 1. INDIVIDUAL GENERATOR SET VERSUS PARALLEL BUS CAPABILITIES

Individual Generator Set Ratings	Bus Rating with Three Generator sets
Generator set Steady State kW: 500 kW	Bus Steady State kW: 1500 kW
Steady State kVA: 625 kVA	Steady State kVA: 1875 kVA
Short Circuit Performance: 5000 A	Short Circuit Performance: 15000 A
Surge (Momentary Overload) kW: 525 kW	Bus Surge kW: 1575 kW
Motor Start kVA: 1150 kVA	Motor Start kVA: 3450 kVA

We see examples of paralleling every day. For example, what person has not put a set of batteries in a flashlight? By putting the batteries in series, the effective battery voltage doubles, and by putting the batteries in parallel, the voltage stays the same, but the current available from the batteries is doubled.

Batteries are easy, of course, because they are DC power sources, so they can be easily paralleled as long as they are the same voltage. With AC sources, and their constantly shifting absolute voltages, paralleling is more difficult, but the results are the same: the voltage of the AC sources is held constant, but the effective power available from the sources goes up with the number of sources that are connected.

Paralleling is the simultaneous operation and control of alternating current machines in a fashion that allows them to act as a single large power source.

2.3.1 Benefits of Paralleling

On first inspection, it would seem reasonable to presume that the primary reason to parallel is to get added system capacity.

The benefits of paralleling generator sets at a site, beyond increased bus capacity, can also include:

- Enhanced Reliability
- Improved Performance
- Servicing Convenience
- Cost Savings

The advantages are not automatically achieved by simply adding more generator sets in the system, but will accrue in a system with proper system design.

2.3.1.1 Enhanced Reliability

In standby/emergency applications, the probability of providing power to a critical load during a normal power failure is considered to be greater when multiple generator sets are available to service that critical load. The more generators there are in the system, the better the probability that first priority loads will be supplied. The use of multiple generator sets allows the customer to keep critical processes running, even if a portion of the system fails.

Paralleling is commonly recommended in applications that require higher reliability than can be achieved with an individual machine.

On the other hand, reliability of service to non-critical loads is actually decreased, unless redundant generator sets are included in the system design. By definition, redundancy means that there is an extra generator set available that is not necessary to serve the system loads. More generator sets doesn't equate to greater reliability to all system loads unless the system has redundant machines.

The redundancy argument in favor of paralleling also depends on the assumption that the individual machines are equally as reliable as a similar machine without paralleling. This is difficult to achieve in practice with many paralleling systems, as they depend on the addition of many extra components in order to provide paralleling functions. In digital (microprocessor-based) systems, however, where paralleling is achieved using the same core components as the basic machine, reliability can be effectively enhanced.

To achieve greater system reliability with paralleling, the designer must include provisions for load management (especially for emergency/standby applications) and maintain individual generator set reliability levels. Redundancy allows higher reliability of service to lower priority loads if control system reliability is maintained, because the maintenance of redundant capacity on line makes it possible to power more loads in the event that a generator set fails. So, if added capacity is available, lower priority loads are less likely to be shed. The table below illustrates how redundant generators increase the reliability for critical loads. This table assumes that each generator has a reliability of 98% and each generator is large enough to carry the critical loads. Note that in order to attain increased reliability to critical loads through redundant capacity there needs to be a load shedding scheme to take the non-critical loads off line, decreasing the reliability of the non-critical loads.

For example, if we have 2 paralleled generator sets each with capacity to carry the critical loads, there would be N+1 redundancy for the critical loads and the reliability would be 99.96%. There would be no redundancy for the non-critical loads so the reliability for these loads would be 96.04%, lower than what it would be if they were served by a single generator set. If a third generator set is added to the system, reliability of service to the most critical loads increases to 99.999%, and reliability to second priority loads is 99.88% because there is N+1 capacity relative to those loads.

It is extremely important to note that all these calculations assume that the paralleled generator set is just as reliable as a single generator set. So, the more hardware and interconnecting equipment used in the system, the lower the reliability actually will become. It is very important to consider this fact as the equipment of different suppliers is evaluated for a specific project.

TABLE 2. REDUNDANT GENERATOR SETS AND SYSTEM RELIABIILTY

Number of Paralleled Generator Sets	Level Redundancy for Critical Loads			
	Level	N+1	N+2	N+3
1	98.00			
2	96.04	99.96		
3	94.12	99.88	99.999	
4	92.24	99.77	99.997	99.99998

As the table above shows, the reliability of service to first priority loads improves but lower priority loads drops if there are no redundant generator sets. Adding redundant generators improves the reliability of service to all the loads.

2.3.1.2 Improved Performance

Paralleling can improve performance of loads by providing a larger capacity (lower impedance) source relative to the loads being served, even when the total percent of load on the machines is the same. This advantage is difficult to quantify, but will have benefits in reducing the voltage dip and improving the recovery time when starting motor loads. For example, a 600 kW generator running with 500 kW load will experience a voltage dip of about 6% when a 50 hp motor comes on line. If we have 3 of these 600 kW generators running in parallel with 1500 kW load and the same 50 hp motor comes on line the voltage dip will be only 2%. (Calculations based on GenSize tool with 600 DFGB generator sets.)

In applications that have a high percentage of load-induced harmonics, a single large bus is less susceptible to harmonic distortion than several smaller ones. Thus, it may be better to group linear and nonlinear loads on a common bus rather than isolate the nonlinear (harmonically distorted) loads on a separate bus.

When a single large prime mover is used, breaker size limitations may force the customer to operate at medium voltage (over 600 volts). Because most emergency loads operate at low voltage, the necessary transformers and added distribution equipment add other potential failure points into the system. Paralleling several smaller sets eliminates the need to operate at medium voltage and removes the extra potential failure point.

2.3.1.3 Servicing Convenience

The use of multiple generators allows the customer to take a generator out of service for routine maintenance or repair without the loss of power to critical loads. System downtime is further minimized because parts and service for smaller, more common generator sets are more readily available.

This eliminates the cost of renting and installation of back-up generators, which are required by codes and standards in some locations and with some types of applications.

The U.S. National Electrical Code (NEC-NFPA 70) requires that an alternate source of standby power ”be available whenever the emergency generator is out of service for major maintenance or repair." This requirement is satisfied by the use of multiple generator sets in a paralleling installation when optional standby loads that are equal or greater than the capacity required for the emergency loads are available to be shed.

NOTE: Region specific codes/standards require an alternate source of standby power to be available whenever the permanently installed emergency generator is out of service for maintenance or repair.

Multiple unit systems can be more efficiently exercised at higher load levels by using non-critical loads that might be too small if they were broken between individual generator sets, but grouped together serving a smaller number of machines can eliminate or minimize the need for load banks for exercise periods which are required by some codes and authorities for some applications such as healthcare facilities in the United States.

The use of multiple generator sets allows the customer to run only the number of sets required to carry the loads in use. This allows the running set or sets to operate more efficiently (at higher load levels). This more efficient operation reduces fuel consumption and operating problems related to light load operation. (Operating diesel engines at light loads levels will eventually cause engine damage or poor performance through a build-up of unburned or partially burned fuel in the injectors. See T-030 for more information on this topic.) Running generator sets at optimum fuel consumption rates can also help to keep facilities in operation over long normal power outages.

Paralleling can also be used to operate a generator set with a utility (mains) service, or other generator sets, so that power transfer can occur between sources without a power interruption to the load devices. For example, if it is desired to exercise a generator set under load, paralleling controls can be used to synchronize a generator set to the service, parallel the generator set to the service, and then disconnect the utility service. At this point the power has been transferred to the generator set without disturbing load devices. The process is repeated to transfer loads back to the utility (mains) service.

Paralleling can also be used to exercise generator sets by paralleling the generator set to the utility and operating the generator set in parallel with the utility for the test period. This has the advantage of fully loading the generator set, and recovering part of the value of the fuel consumed in reduced utility electrical costs. (Note this exercises the generator sets, which is necessary, but does not necessarily test the system, which may be also be required on a regular basis.)

2.3.1.4 Cost Savings

In general, paralleled generator sets will cost more than a single generator set of the same output capability (if they are all high speed machines). This factor is driven by incremental paralleling costs for both hardware and installation, as well as the cost of providing the additional space needed for multiple generator sets. Incremental hardware costs include the costs for the paralleling controls for each generator set, system controls to provide supervisory control functions, and more expensive electrically operated circuit breakers and the switchboard equipment to hold them. Installation costs are driven from the need to set and install multiple machines rather than one, and the interconnecting wiring between them.

However, as facility power needs grow, it becomes impractical to purchase a single generator set with adequate capacity to serve specific facility loads. Multiple smaller high speed (1500 or 1800 rpm) machines will be considerably less expensive to purchase and install than larger, lower speed equipment because lower speed machines (1200 rpm and less) cost as much as twice the cost of high speed machines on a cost per kW basis.

In interruptible or prime applications, fuel savings due to operating engines only when needed and at optimum fuel consumption rates can be significant and in some cases running more, smaller generator sets may use less fuel than running fewer larger generator sets for the same kW output. In addition, shutting down sets that are operating at light load levels reduces maintenance costs and increases longevity. Thus, in prime power applications it is common to have multiple generator sets with multiple ratings, so the power system can operate at optimum energy efficiency levels rather than using a single larger machine. This is also a factor in emergency and standby operations during extended normal source outages.

Costs per kW are lower on smaller 1800 or 1500 RPM generator sets than on larger, lower RPM sets. For facilities where total system load is more than approximately 2500 kW, it may be economically advantageous to use a paralleling system based solely on the initial cost of generating equipment.

With a single larger low speed generator set operating at low voltage, the cost of breakers and other system components may be greater than with a paralleling system, which would have smaller generator sets and lower ampacity breakers. If the choice of a single larger set forces the customer to use a medium voltage system, the cost of required system components is even greater.

Installation and support equipment costs are typically lower on several smaller kW high speed generator sets than they would be on one large low speed set. These costs include:

- Transportation and rigging

- Foundation and structural support costs may be reduced, because equipment weight can be spread around.
- Easier wiring and termination due to smaller conductors.
- Support equipment, such as remote radiators, oil level maintainers, starting batteries, and exhaust systems.
- The lower physical height of smaller sets paralleled may be an advantage in applications where the ceiling height is limited. Multiple generator sets can help to spread the weight of the equipment across a larger mounting surface when installed on structures that have limited load bearing weight levels.
- Service and repair parts are generally less expensive and more readily available on 1800/1500 rpm sets than they are on 1200 or lower rpm sets, because of the higher production volumes of the higher speed machines.

When evaluating total cost of ownership, the criticality of the installation will impact on the decision on the degree of redundancy that is built in to the system. Some local codes and standards require continuous service to legally required loads and the critical nature of some facilities may require similar service provisions. These factors drive the need for greater redundancy. In other cases codes require power availability only for the length of time necessary to evacuate the facility, so it is harder to justify redundant machines. If generator sets are paralleled, the maintenance cost and temporary down time associated with temporary generator sets can be avoided. These considerations may also impact on the number of sets required for the installation.

There are also cases where paralleling can save money by improving the operational efficiency of an application, or by providing power with other cost reducing characteristics.

The use of multiple generator sets allows the customer to purchase only the capacity currently needed, but allows better flexibility to add capacity in the future, without having to replace existing equipment. With proper planning, future additions can be made with a minimum of disruption to the operating facility.

NOTE: **Paralleled generators provide higher reliability and greater system bus capacity leading to better performance, service convenience, and in some applications, cost savings.**

NOTE: **The incremental cost of paralleling can be minimized by carefully considering the degree of redundancy needed in the system.**

2.3.2 Disadvantages and Risks

With all these advantages, one might be inclined to provide paralleled generator sets on many projects. But this is not done often. So, what are the disadvantages and risks of paralleling?

Not all applications are suitable for paralleling. Some inappropriate applications may include facilities where:

- The relative cost of the switchgear compared to the generator sets may outweigh any advantages gained by using multiple sets.

- When one 300 kW (or smaller) generator set can handle the load, paralleling may not be economically desirable. Paralleling is most economically advantageous in applications with a total load greater than 1000 kW. However, when an application demands the reliability or serviceability achieved by redundant generator sets, it is reasonable to parallel with generator sets as small as 30 kW. (Smaller generator sets are slightly more difficult to operate in parallel than larger machines, due to less precision in the frequency regulation in these units.)
- The applications where loads cannot be split (for controlled load adding or load shedding), or all loads in the application are of equal importance. In many computer facilities, for example, the load is divided into an uninterruptible power supply (UPS) load and an air conditioning load. Because both loads are equally critical to the operation of the computer facility, and effective load adding/load shedding is not possible, some of the benefits of a typical paralleling system are lost. Alternatives include a single standby generator set, or multiple generator sets in a redundant/parallel configuration.

When paralleling with existing generators that have different control systems or alternator pole pitch or are otherwise incompatible the project can become quite complex. If the compatibility issues cannot be resolved, the incompatible equipment must be replaced with compatible generators or paralleled operation should not be attempted. Refer to the Special Design Considerations/Paralleling Dissimilar Generator Sets (Section 7.4.3 on page 216) section.

Bus short circuit capacities are higher, so there is greater chance of damage if there is a catastrophic fault or an arcing fault condition. Careful selection of generator short circuit capabilities can minimize this exposure. But remember, the higher capacity also helps the transient performance and voltage waveform quality.

Greater control complexity in traditional design systems can lead to decrease in reliability and difficulty in service. (More complex service problems require higher "class" of service technician, parts support, etc.) This issue can also be addressed by use of standardized equipment, and avoiding custom designs. In many cases, there will be enough commonality in facility design requirements that a standard design or series of standard designs could be carefully produced that would be nearly the same at multiple application sites.

There is a greater risk of misoperation of the system in case of operator error. Regular operator training is required to minimize the impact of this problem. Use of posted operating instructions also minimizes this problem.

2.3.3 Principles of Paralleling

Paralleling systems, regardless of their size and complexity, are all subject to physical laws that cause them to react in ways that you might not expect. So, it is good to keep these principles in mind when attempting to understand how paralleling systems operate.

Perhaps the biggest thing to remember is that in an electrical system, the voltage at any point on a common conductor is constant (neglecting the effects of impedance, which is not significant within a paralleling switchgear lineup). This factor is prominent because it causes the two active control systems of generator sets (the fuel control system and excitation control system) to perform differently when paralleled than when the generator set is running isolated from other generator sets.

Since the voltage on a common bus between paralleled machines must be constant, then if two generator sets are operating at different voltages prior to closing to the bus, they will be forced to operate at the same voltage when operating on the bus together. If one generator set is trying to operate at a higher voltage than another, rather than increase voltage, it will pick up additional (reactive) load.

Since the voltage must be the same at every point on the bus at every instant in time, the 0-crossing points of each generator set must be the same. The voltage wavelength period is defined by the frequency, and the frequency is directly related to the position of the rotor within the stator of the alternator. So, the frequency of the machines must be identical. If generator set 1 in the figure below is generating a sinusoidal voltage and energizing a system bus, when generator set 2 is paralleled with 1, it must have matching voltage and frequency. The frequency 0-crossings are synchronized between the two machines.

NOTE: When multiple machines are operating in parallel the voltage on the common bus between them must be constant, and frequency and the phase sequence of the two are identical at all times.

If the frequency on a common bus is constant, that means that even if two generator sets are operating at different speeds prior to closing to the bus, they will be forced to operate at the same frequency when operating on the bus together. If one generator set trying to operate at a higher frequency than another, rather than increase in frequency, it will pick up additional (real) load.

NOTE: Attempts to change voltage and frequency of generators operating in parallel will cause load change rather than voltage or frequency change.

So, if the load on a paralleling system is not shared proportionally between the machines in a paralleling system, variations in real kW load will be adjusted by attention to the fuel controls on the generator sets, and variations in the reactive kVAR load will be adjusted by attention to the generator set excitation systems.

The figure below shows the difference in voltage across a paralleling breaker for a single phase (versus time), when a generator set is synchronizing to a system bus. As the generator set is synchronizing to the bus, the voltage across the breaker increases as the generator set becomes further from synchronized condition. When the generator set is exactly synchronized with the system bus, the difference in voltage between the two sources (generator and bus) is zero, and this indicates that they are synchronized and can be safely paralleled. See Paralleling System Controls Section 3.4.3.1 on page 31 for more information on synchronizer types.

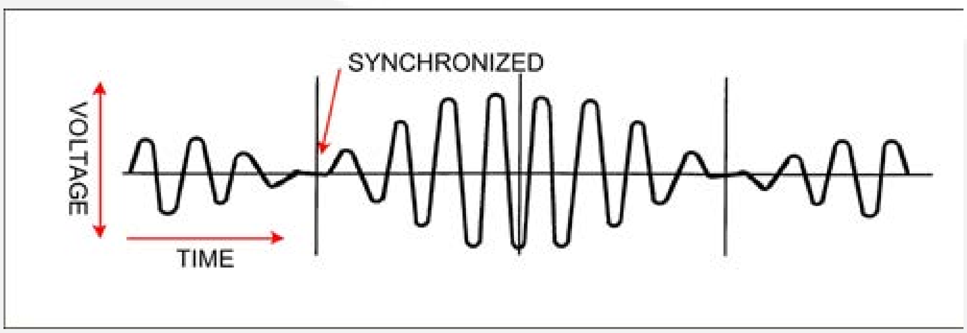

FIGURE 2. VOLTAGE ACROSS A PARALLELING BREAKER. WHEN VOLTAGE APPROACHES ZERO, THE BREAKER CAN BE CLOSED. THIS VOLTAGE VARIATION INDICATES USE OF A SLIP FREQUENCY SYNCHRONIZING SYSTEM.

We will look at all these phenomena in more detail later in Chapter 3, but what this means is that in addition to the governing and voltage regulation systems, each generator set in any paralleling system must be supplemented by other control system functions. These will include means to control the load on each machine in the system, means to synchronize the equipment, and usually additional protective devices.

2.4 Major System Components

In order to simplify discussions and to get a clearer understanding of system functionality it is useful to think of paralleling systems being broken into several major functional blocks of equipment. Any system for a specific application can be built using the building blocks of generator sets, paralleling controls, master (supervisory) controls, power transfer controls, and power sections (circuit breakers, bus bar, and related equipment).

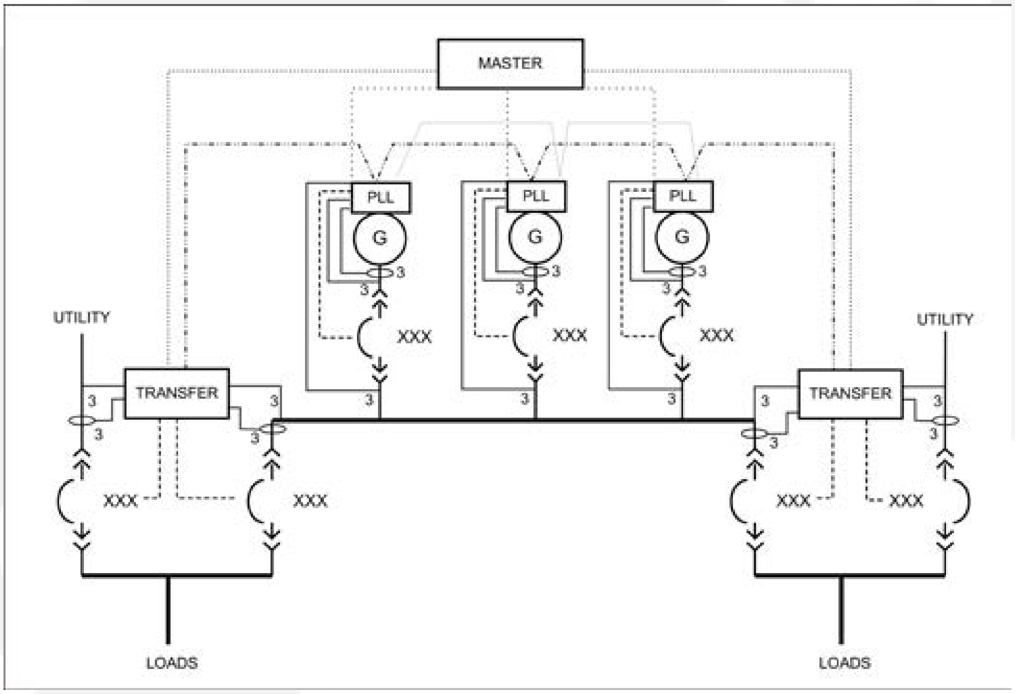

FIGURE 3. BLOCK DIAGRAM OF A PARALLELING SYSTEM

The paralleling system will have a paralleling control for each generator set, usually a master (totalizing) control to act as the interface between the generator and paralleling controls and the rest of the facility, and power transfer controls. Power is transported from the generator sets through power sections that include breakers that connect the generator sets to the common bus, and feeder breakers for system loads. Transfer switches or breaker pairs are commonly used to switch power from the normal facility power source to the generator source in emergency/standby applications.

As noted, there will be one paralleling control for each generator set and a paralleling breaker for each generator set. There will generally be one master control for the generator power system. The number of generator sets used and the number of transfer switches or breaker pairs, and the number of feeder breakers is a function of system design requirements. This will be addressed in greater detail in Chapter 5 on page 105.

2.5 First Considerations in System Design

The process of establishing a design for a facility involving paralleling can be characterized by the following sequence of work:

- Develop a load profile for the facility and prioritize loads into critical (most important), essential, and convenience, or optional loads. Some regions and applications have specific requirements for load priority and sequence. For example, in North America, detailed requirements have been established for loads that must be served and their priority for hospital applications. In most cases there are either code-driven or customer-driven requirements for the duration of time that the most critical loads in the facility can be without power.
- Establish the level of reliability required. Is there a need for redundant generator sets in the system?
- Determine if there are likely future system expansions.
- Estimate load factor on the generator sets in expected service. This will impact on the type and size of generator set that is specified, and may impact on the test/exercise sequences necessary in the facility sequence of operation.
- Decide on the general topology best suited to the application, and determine overall sequence of operation.
- Establish details of the system one-line arrangement, and switchboard/switchgear configuration.
- Check the available fault current from the utility (mains) service, and calculate the fault current available from the generator sets. Establish fault current requirements for switchgear and transfer switches.
- Determine generator set distribution switchgear requirements. Verify short circuit requirements and establish bracing and ratings requirements.
- Determine overload protection requirements for generators, cables and all equipment.
- Establish overall space requirements for system. Verify that mechanical requirements can be met in the installation.
- Finalize detailed sequence of operation for system as a whole. Identify single points of failure in the system, and decide on necessary actions to either eliminate the failure point, establish a fallback position such as redundancy, or define quality requirements for functions/equipment that represent points of failure that cannot be addressed by other means.
- Review system design for local code compliance.
- Establish budget system pricing.

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3 Paralleling System Controls

3.1 Overview

This section covers the functions and equipment necessary to parallel generator sets. It covers first, the functions that must be provided for each generator set control in the system and then addresses equipment that can be used to provide these functions. The section concludes with descriptions of the functionality required in master control systems and power transfer control systems, and equipment commonly used to provide these functions.

3.2 Requirements and Recommendations

3.2.1 Requirements

- Generator sets used in isolated bus paralleling applications (those where the generator sets never parallel to the utility/mains) must be provided with synchronizing capability, load sharing capability, protective functions, and manual back-up devices, in addition to their standard control systems, in order to parallel safely and successfully. These functions can be provided in many different forms of hardware.
- Generator sets used in infinite bus (utility/mains paralleling applications) must have a means to control kW and kVAR load on the generator set while interconnected with the grid. In general, these means function best when they are insensitive to frequency and voltage changes over the normal frequency and voltage ranges of the utility system but local utility service provider requirements will dictate required control arrangements. These systems typically also include all the features of isolated bus systems.
- Generator sets used in utility parallel applications are required to have two protective devices not commonly used in isolated bus applications: a reverse power relay (ANSI device 32) and a loss of field or reverse VAR relay (ANSI device 40).
- Reverse power protection must be set to trip at a level that is less than the minimum expected motoring kW load the engine will impose on the system. This level is commonly in the range of 5% of the standby rating of the generator set.
- Reverse VAR protection must be set based on the reactive current capability of the alternator. The set point for this function varies widely by alternator design, voltage, and other factors. The alternator capability curve for the specific machine provided must be provided to the designer to allow proper setting of this device.
- When multiple generator sets are synchronized simultaneously to a utility source, a master synchronizer must be provided.

3.2.2 Recommendations

- The synchronizer can make a stable governor unstable as it operates through the load sharing system to match the zero-crossing points of the two sources. This is of concern in emergency paralleling systems as they normally operate when the engine is “cold”. Thus it is important that a paralleling system is initially site-tested under cold-starting conditions, as well as any time when there are governing adjustments in the system.

- Manual back-up provisions should be provided for critical paralleling functions, including manual synchronizing, manual paralleling breaker control, and in case the automatic control system fails. They are also used for system start-up and service work. Note that “manual” does not mean “without any control or protection”. In nearly all systems, “manual” is more appropriately defined as “operator initiated”, as most control operations include some level of protection to prevent catastrophic damage when the system is misoperated.
- Settings of protective devices in a paralleling system should be selected based on the needs of the device or equipment the specific protective device is intended to protect, and to coordinate with other devices in the system.
- Easy set-up and adjustment, reliability, serviceability, functional requirements, flexibility and cost are some of the deciding factors for choosing the right hardware for an application.
- In emergency/standby applications the master control acts as the interface between the generator sets and paralleling controls and the rest of the system in a specific facility. Thus depending on the facility needs, the functionality of the master control varies.
- In prime power applications there may be no master control, or the master control or system level functions may be completely different than in emergency applications. Prime power systems may include power station management functions, remote monitoring and control systems, and other functions. More information on power transfer systems is discussed in Cummins Power Generation Application Manual T-011, which is available on request.
- The operator working on the manual controls must be well trained and technically competent. Posted instructions for critical operator functions and regular training are recommended.

3.3 Generator Set Control System Basics

Each generator set in a paralleling system must be provided with a control system that will control, monitor, and protect the generator set through all its operating modes, and also interface effectively with other generator sets in the system and components in the overall facility. Each generator set in the system must be provided with an individual set of controls as described in the next several sections in order to properly and reliably operate with other generator sets in the paralleling system.

NOTE: Generator sets used in isolated bus paralleling applications must be provided with synchronizing capability, load sharing capability, protective functions, and manual back-up devices in addition to their standard control systems, in order to parallel successfully. These functions can be provided in many different forms of hardware.

3.3.1 Basic Generator Set Controls

Before getting into the functions of a generator set which are related to paralleling, it is important to understand the basic control functions of a generator set. All generators set, of any size and manufactured by any company, are similar in the fact that they all have at three distinct control sub-systems: an engine speed (frequency) control system, an alternator voltage control system, and an engine control and protection system. These sub-systems function in a similar fashion for all generator sets. The figure below shows a functional representation of control functions in a generator set.

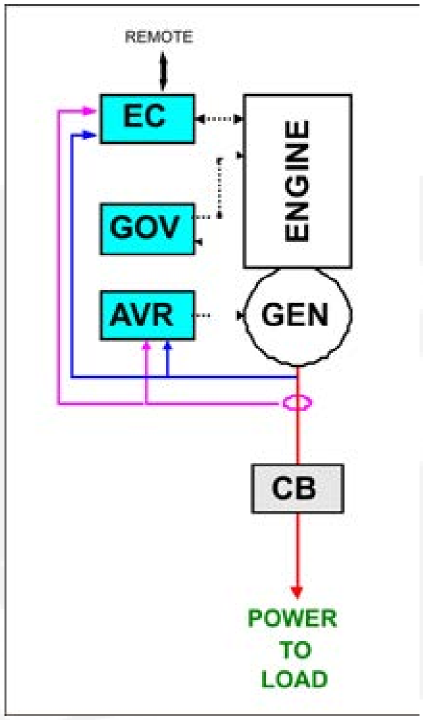


FIGURE 4. BLOCK DIAGRAM - TYPICAL NON-PARALLEL GENERATOR CONTROL SYSTEM.

The engine speed (frequency) governing system for large generator sets is typically composed of three major control subsystems. These are a governing system, including a magnetic pickup unit (MPU) which is used to sense engine speed; a governor control (GOV) which monitors the magnetic pick up (MPU) on the flywheel and provides control signals to the governor actuator; and a engine actuator (ACT), which controls the amount of fuel fed into the engine. (Emission-controlled engines will have much more complex control systems and different physical configurations than this design, but from a control perspective they regulate fuel to the engine based on these parameters.) The system functions by sensing the engine speed by the MPU and comparing it to a preset speed point. When the engine is “off speed” the governor control adjusts the fuel rate signal to the actuator to increase the fuel rate if the engine speed is too low, and decrease the fuel rate if the engine speed is too high. So, in a non-paralleled generator set, the fuel rate of the engine is a direct function of the speed of the engine. The speed, of course, is directly related to the frequency output of the alternator, so maintaining speed at as constant a level as possible is desirable.

At the same time, it is important that corrections to speed be done in a fashion that does not leave the generator set subject to unstable operation due to corrections to the fuel rate that are made too quickly. The actual “correction rate” or rate of change of fuel signal, called the governor gain, can be problematic because a typical engine is more stable when it is at normal operating temperature than when it is cold. In older control systems the governor was often detuned to make it more stable when cold. With digital controls[1] used on emission-controlled engines, governor controls often include temperature compensation functions that correct governor gain as a function of engine temperature. This greatly improves the stability of the engine without sacrificing transient performance capability in an engine running at normal operating temperatures.

[1] Cummins PowerCommand® generator sets have included this function since their introduction in 1994.

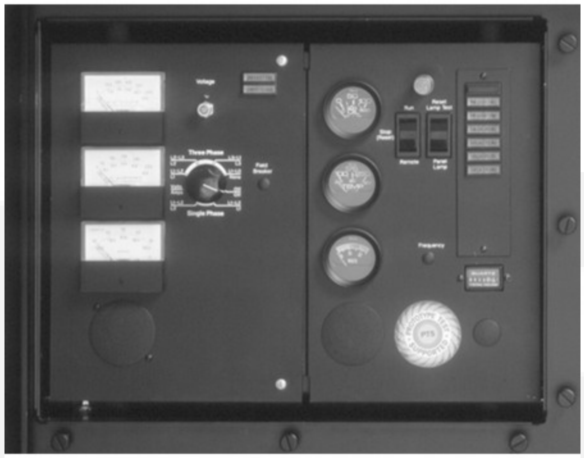


FIGURE 5. EARLY GENERATOR CONTROL PANEL WITH ANALOG METERING AND CONTROLS

The voltage regulation system operates in a similar fashion to the governor to control the output voltage of the alternator. An automatic voltage regulator (AVR) senses output voltage on the generator set and sends correction signals to the alternator exciter to raise or lower the field strength of the alternator, which causes the voltage of the alternator output to rise and fall. As the AVR senses output voltage start to fall, it increases the excitation level of the alternator field, and voltage recovers to normal level. The excitation level of the alternator is a direct function of the voltage measured on the output of the alternator.

The engine control (EC) functions are relatively straightforward. The engine control is used to start and stop the engine, and to sense failure of critical engine systems (like lube oil pressure and coolant temperature) so that the engine can be protected and serious damage to the engine can be avoided, allowing the engine to operate in unattended applications. In addition, the engine control system commonly includes the operator interface to the equipment, which provides capabilities such as AC metering, indication lamps showing the status of the equipment (for example, NOT IN AUTO), the presence of fault conditions, and mode control switches (for example AUTO/OFF/RUN or OFF/MANUAL/AUTO with manual start switch). Note that emission-controlled engines have much more complex control and protective systems than are described here, but the functions described here are on generator sets.

Generator sets can have many other control subsystems for many other control and protective functions, but they always have the three basic control functions described here. These basic functions are also necessary for operation of the equipment in paralleling applications. They are the primary controls that operate the generator set before the paralleling breaker closes.

3.4 Generator Paralleling Control Functions

3.4.1 Isolated Bus Paralleling Functions

All generator sets that are paralleled with other generator sets have at least two other control sub-systems, automatic load sharing controls for real (kW) and reactive (kVAR) loads, and synchronizing controls. Controls for generator sets in paralleling applications usually have a number of other sub-systems, including generator set protective equipment, manual controls and AC metering, and alarm indication panels.

When generator sets are paralleled with each other on a common bus, the voltage and frequency of the generators must be exactly equal. In fact, they are forced to exactly the same values once the breakers are closed together connecting the machines to a common system bus. (Remember that if you have electricity running through a short length of conductor, the frequency and voltage along the entire length of the conductor is exactly the same. When generators are closed together on to a common bus they must have identical voltage and frequency simply due to these same physical laws.)

The practical impact of this fact is that the conventional control systems that are provided on non-paralleled generator sets do not have sufficient controls for the engine and alternator in paralleled applications. The excitation level of the alternator and fuel rate of the engine are no longer directly related to voltage and speed, because the speed and voltage of the engine are forced on to the generator set by the system bus.

Since the speed of the engine is controlled to a fixed level, increasing the fuel rate of the engine increases the amount of horsepower produced by the engine without changing the speed. With a fixed bus voltage, increasing the excitation level of the alternator increases the amount of reactive power produced by the alternator. So, in isolated bus paralleling applications we need to provide additional control equipment to allow the fuel rate of the engine to be controlled as a function of the load on the engine while retaining the speed (frequency control) function. [fuel rate = f (hz, % kW load)] The excitation level of the alternator must be controlled as a function of reactive load on the alternator, but likewise, must also retain control of system voltage. [Excitation rate = f (voltage, % kVAR load)]

These additional control provisions are called real and reactive load sharing controls.

The figure below represents how a load sharing control system modifies the basic generator control operation to cause fuel control to be a function of speed and % kW load; an excitation system control to be a function of voltage and % kVAR load.

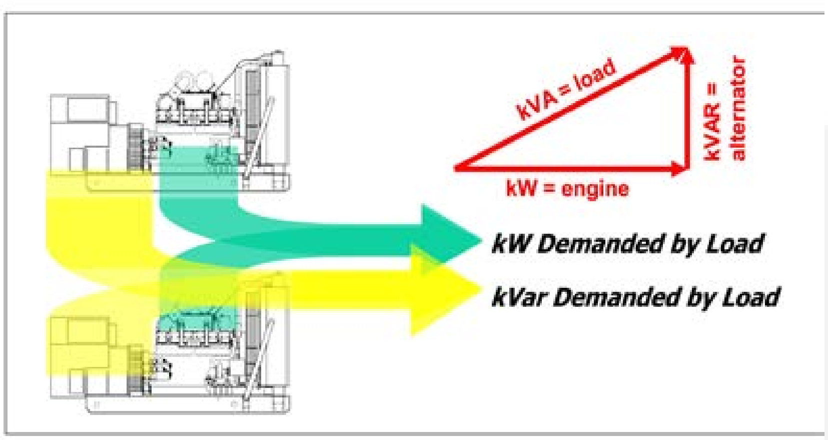


FIGURE 6. LOAD SHARING CONTROL VERSUS EXCITATION SYSTEM CONTROL.

NOTE: **All generator sets in paralleling applications must have at least two other control sub-systems, automatic load sharing controls for real (kW) and reactive (kVAR) loads, and synchronizing controls.**

3.4.2 Load Sharing Controls

The goal of a load sharing control system is to cause multiple generator sets to operate at the same percent of load while sharing the total load on the system bus. (See Figure 6 on page 21.) So, the percent of load (based on generator set capacity) and the percent of system load capacity are the same in steady state.

Load sharing controls for generator sets operating on an isolated bus may be either droop or isochronous in their operating characteristic. The difference between droop and isochronous is simple: In a droop system, the voltage or frequency drops as load increases. In an isochronous system, the frequency and/or voltage is constant from no load to full load. (See figure below.) There is no requirement for the controls of the engine and alternator to both be of the same type (droop or isochronous).

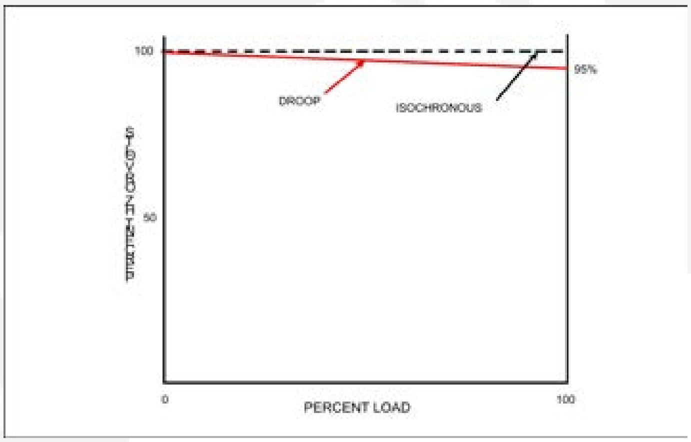


FIGURE 7. A DROOP CONTROL SYSTEM CAUSES THE FREQUENCY OR VOLTAGE TO DROP AS LOAD INCREASES.

In general, droop control systems are much simpler in their design than isochronous control systems. So, sometimes they are considered to be more reliable than isochronous. They do not require the control systems of the generator sets in the system be of the same type or manufacturer in order to operate properly.

However, since the voltage and frequency change with changing load, the quality of power provided to the load is not as good with droop as it is with isochronous controls. This is a particular issue with loads that require more precise frequency to operate properly.

Some prime power systems utilize droop control systems but an operator constantly adjusts the system to maintain system frequency.

In an isochronous control system the engine speed and alternator voltage are constant over time (not considering changes due to transient conditions). So a control system must be provided that can measure the kW and kVAR produced by the generator set, compare that load to the percent of system load, and make fuel rate and excitation system adjustments automatically to maintain proper load levels on each generator set in the system.

3.4.2.1 Real Load Sharing Controls

As load increases on an engine, the speed in the engine will drop unless the fuel rate to the engine increases. As we have seen, in generator sets engine governors are used to regulate fuel rate to maintain constant speed as the load on the generator set changes.

In a droop governing system, the engine governor is adjusted to allow the speed to drop as load increases. In effect, the engine fuel rate increases as load increases, but not quite enough to recover the speed to the no load speed of the engine. When generator sets are paralleled with droop governing systems, they are set to all operate at the same no load speed, and the same droop rate. As load increases on the system, the speed of each generator set drops the same percent from no load to full rated load. If an engine tries to pick up more load, its speed drops, which inherently makes the load drop on that machine. So, droop governing forces engines in a paralleling system to operate at the same percentage of full load, even if the machines are of dissimilar size.

In general, in a droop governing arrangement the engine no load speed is set so that with the system operating at expected load levels, it will be as close as practical to rated operating frequency (50 or 60 hertz). An operator can adjust the system frequency by manually adjusting the fuel rate (often labeled as speed control) of all the generators in a system to get a system back to rated frequency. Note that if only one machine in a system is adjusted, a load sharing imbalance results, so any correction in system frequency requires ALL the machines to be adjusted. If this is done manually, a trained operator is required to prevent load imbalances or reverse power conditions on one or more generator sets in the system.

For isochronous kW load control on the engines in a system an isochronous load sharing control (ILS) is added to the system (see figure below). The isochronous load sharing control uses voltage and current information from the generator output to calculate the kW load on the generator set as a percent of rated generator set capacity, and then compares it to the output of other generator sets (percent of system load) that are paralleled on the same system bus. It then sends correction signals (called speed bias signals) to the governor control to cause the engine to increase its fuel rate to increase load applied to the generator set, or decrease fuel rate to decrease the amount of real load on the generator set.

The isochronous load sharing comparative signals that are necessary to maintain system load sharing operate on load sharing lines. Load sharing lines are typically twisted pair wiring, often with shields, to protect the signals from being disrupted by external magnetic fields. The load sharing signals may be analog signals that vary in either voltage or current from no load to full load. So, the signals effectively communicate the percent of full load at which the generator set is operating. This means that, as with droop systems, generator sets of varying sizes can be interconnected and operate in parallel using isochronous load sharing controls.

Load sharing lines may also use proprietary network communication protocols, again, usually operating on twisted pair wiring such as an RS485 physical layer. These signals may operate in CAN protocols, but there is currently no industry standard for this protocol, so generator sets that use network communication arrangements must all have governors and load sharing controls from the same manufacturer, and often of the same model control. This can severely limit the ability of the owner to expand or even repair the system as equipment ages and the original components are no longer produced by the manufacturer.

Isochronous load sharing controls (ILS) sense amps and volts, calculate kW, and compare generator set load level with system load level. They provide a speed bias signal to engine governor control to control generator kW load when paralleled.

Isochronous kW load sharing systems operate by sensing voltage and current of the generator set, calculating percent of kW load on that generator set, comparing that generatpr set load to system load, then adjusting fuel rate to maintain proper system load. Load sharing control system is switched on by paralleling breaker closure.

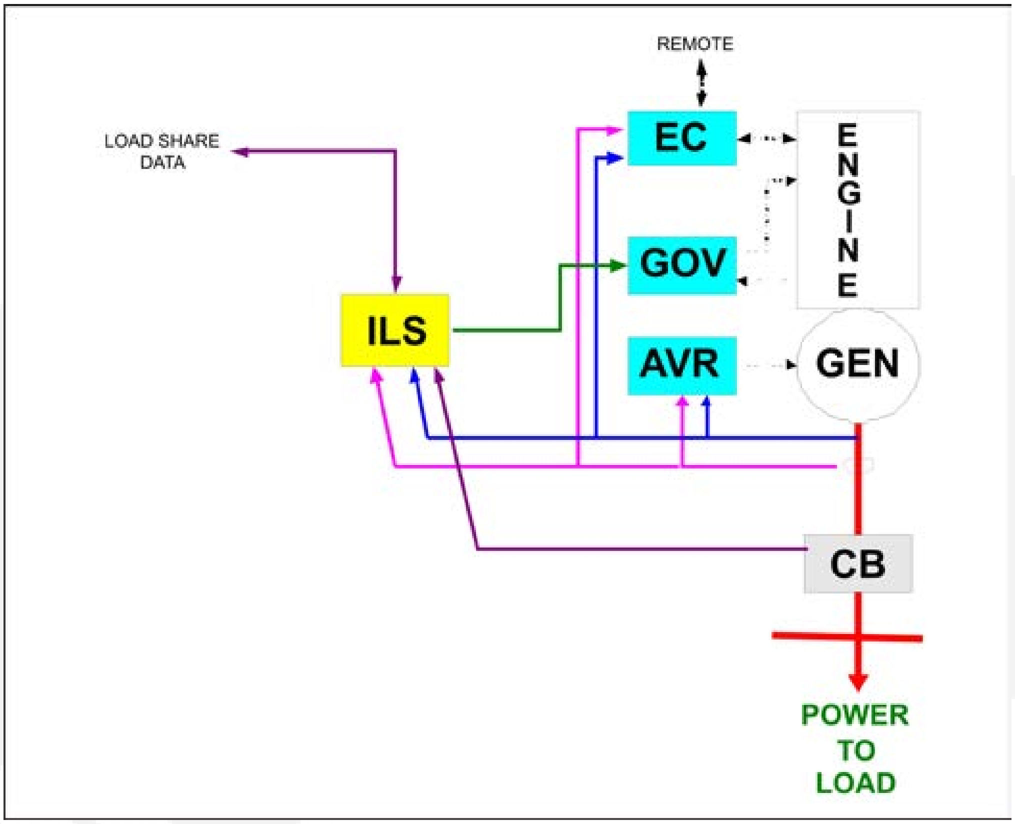


FIGURE 8. ISOCHRONOUS LOAD SHARING (ILS)

3.4.2.2 Reactive Load Sharing Controls

Reactive load sharing controls can be set up to operate in a droop mode, similar to a droop type governor control system. They are called reactive droop compensation systems. The reactive droop compensation system includes current transformer (CT) that measures the amperage exported into the system by the alternator on one phase. (This CT must be in the same output phase of all the generators in the system, so that load phase unbalance does not disrupt load sharing.) The current measured by the CT is fed through a sensing resistor, and a reference circuit of the voltage regulator (voltage bias input) monitors the resulting voltage drop across the resistor. This circuit balances the output voltage of the generators, thereby minimizing cross currents. So, reactive droop system is used to reduce the voltage of the alternator as load increases. (In other words, the voltage of the alternator droops from no load to full load.) All the generator sets are adjusted to the same no load voltage and same droop rate (for example, 4% droop from no load to full load reactive), so they all load share reactive load approximately equally. As with engine controls, if any alternator control system attempt to increase voltage, it picks up load and voltage is forced to drop. So, like droop engine controls, the system inherently controls load sharing as a percent of alternator load. All the alternators in a properly adjusted system operate at the same percentage of full rated current. As with droop governing controls, an operator adjustment of the voltage of one generator set will upset the load sharing balance when the machine is paralleled. If kVAR or power factor monitoring is not provided in the paralleling control, it is difficult for an operator to detect this imbalance or make proper adjustments to correct it.

Generator sets that are not paralleled are typically provided with 1/2 to 1% no load to full load steady state voltage regulation. With reactive droop compensation the voltage regulation is effectively 4% or more. Because utility voltages commonly vary by as much as 10%, the 4% regulation caused by reactive droop compensation is not a problem in most systems. However, if voltage droop is relatively high (8 to 10%), some equipment in the system may not function properly-due to excessive system voltage drop. A mitigating factor in the droop operation is that because droop is set for no load to full load, which is defined as operating at 0.8 power factor and since the loads in a typical system operate at higher power factor, the alternator almost never operates at its maximum droop level.

If voltage droop in a paralleling system is undesirable, “isochronous” reactive load sharing controls can be provided so that load changes do not result in steady state voltage changes. One alternative that provides this function is a cross current compensation system (astatic paralleling) for the generator sets in the system. In a cross current compensation system the voltage regulators of the generator sets in the system are interconnected to all the generator sets to share load approximately equally without the necessity of excessive voltage droop in the system.

The system works by inserting a current transformer (CT) in the output of one of the alternator phases (again, the same phase for all generators in the system), and then connecting the output of that CT into a resistor in the AVR. In addition, the “droop circuits” are cross-connected to each other, so that if the current flow in the monitored phase of each machine is not the same, it causes an imbalance in the cross circuit (see figure below). Note that the cross current system requires interconnection between identical voltage regulators to function correctly.

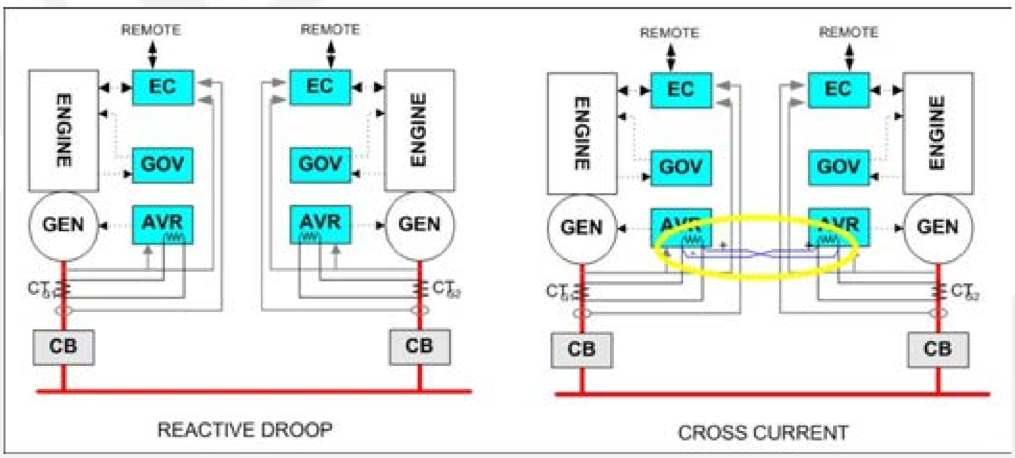


FIGURE 9. COMPARISON OF DROOP AND CROSS CURRENT COMPENSATION FOR VAR LOAD SHARING

This system can be used in applications where all the generator sets in the system have identical voltage regulators, or similar bias circuits.

As with kW load sharing, isochronous kVar load control on the alternators in a system can be accomplished by providing an isochronous load sharing control (ILS) to the system. The isochronous load sharing control uses voltage and current information from the generator output to calculate the kVar load on the alternator as a percent of rated generator set capacity, and then compares it to the output of other generator sets (percent of system load) that are paralleled on the same system bus. It then sends correction signals (called voltage bias signals) to the voltage regulator to cause the alternator exciter to increase its excitation rate to increase load applied to the alternator, or decrease excitation rate to decrease the amount of reactive load on the generator set.

Again, as with the kW load sharing control system, the kVar load sharing controls of the generator sets must communicate over analog load sharing lines or with network signals. In the case of reactive load sharing, analog lines provide an advantage in control in that they operate more quickly than network based lines, providing better load share balance without delay.

3.4.3 Sync Check Devices and Synchronizers

When two sources are synchronized, the instantaneous voltage difference between the sources is zero.

A sync check device will verify that two voltage sources are at the same voltage (within a predefined range) and within a predefined “sync check” or “permissive” window. When conditions are acceptable it allows closing of the paralleling device that connects the generator in parallel the bus voltage source. A synchronizer is used to force a generator set to match the phase angle of its output relative to the bus before the generator is closed on to that bus. In other words, when the generator set is operating at acceptable speed and voltage, the synchronizer forces the on-coming generator set to match its phase angle relative to the bus so that at the instant of paralleling the zero crossing of the generator set is as close as practical to exactly the same as the zero crossing time of the bus voltage waveform (see figure above). So, a sync check device is a passive device that allows paralleling when conditions are acceptable between a generator set and a bus. A synchronizer is an active device that will force the generator set to come into synchronism with the bus.

The sync check device functions by verifying the phase sequence of the bus is the same as the generator set, then monitoring the phase angle of the bus voltage to the phase angle of the generator set voltage. When the sync check senses that the phase angle difference is within tolerance (the “permissive window”), it allows closure of the paralleling circuit breaker, connecting the generator set to the system bus and initiating operation of the ILS control system.

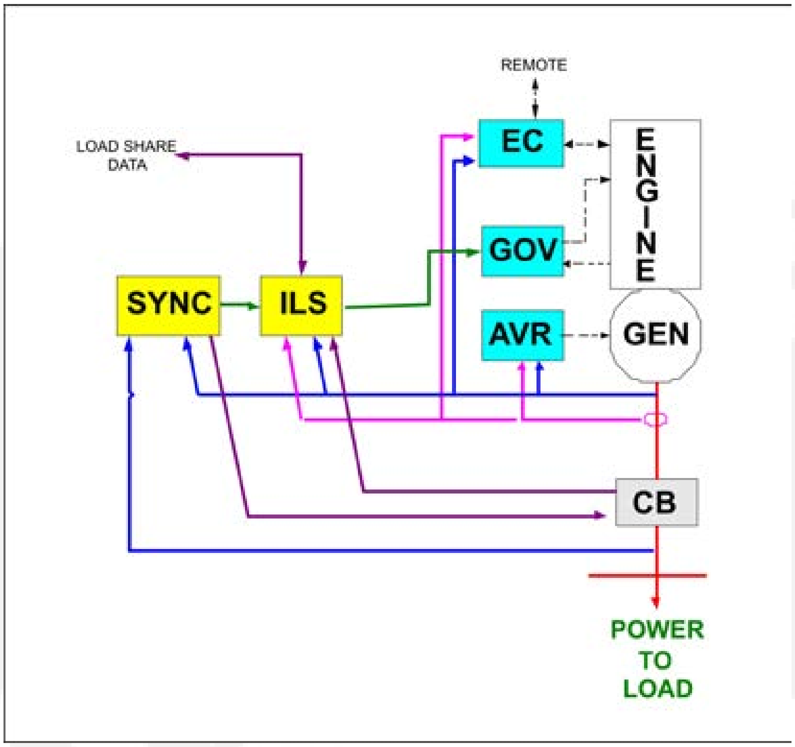


FIGURE 10. A SYNCHRONIZER COMPARES THE DIFFERENCE IN PHASE ANGLE BETWEEN THE GENERATOR OUTPUT VOLTAGE AND THE BUS VOLTAGE, THEN SENDS CORRECTION SIGNALS TO THE GOVERNOR TO FORCE THEM TO MATCH.

A permissive window is used (rather than initiating closure at exactly synchronous condition) because the device that connects the generator set to the system bus is electromechanical, and takes some time to close the contacts from the instant of the signal to close. For example, a power circuit breaker will typically take 5 electrical cycles (approximately 80 milliseconds) to close the contacts from the signal to close. It is also possible that the generator set may be operating at a different frequency than the bus, or the bus may change frequency (for example, due to load change), so in many cases the oncoming generator paralleling device must be commanded to close when the sources are not in synchronism, but are approaching it. Between the time that the command is received and the contacts close, the generator moves into synchronization so that at the instant of contact closure the generator set is “close enough” to in phase that no damage occurs.

Because the failure to close at the correct time can result in damage to a generator set and disrupt system operation, in some systems a sync check relay may be used to verify that the synchronizer has correctly operated to synchronize the generator to the system bus. Some synchronizers utilize separate logic to provide this function.

When a generator is synchronized to a system bus, the voltage acorss a paralleling breaker is minimal. The voltage across the breaker is the sum of the absolute values of the voltage of a single phase on each side of the breaker. When the generators set is out of phase with the bus, the voltage is at its peak. As the generator set is synchronizing to the bus, the voltage across the breaker increases as the generator set becomes further from synchronized condition. When the generator set is exactly synchronized with the system bus, the difference in voltage between the two sources (generator and bus) is zero. This phenomenon has been used for years as the basis for manual synchronizing systems utilizing synchronizing lamps to give an operator a visual indication of when the generator set and bus are synchronized.

Generator sets that are to be paralleled must have the same frequency, voltage, and phase sequence. The sensing of the voltage on the two sources should be carefully selected to not cause a phase shift in the sensed voltage. The sensing circuits should be verified prior to first connection of a generator set to another machine in a paralleling application. (See **Section 8.3 on page 237** for more information on commissioning of generator sets in paralleling applications.)

If the generator set is operating at exactly the same frequency as the bus, the phase relationship between the generator set and the bus will not change. If the generator set is at a different frequency, the phase relationship will constantly change. The greater the frequency difference, the faster the phase relationship will change. So, as a practical matter, the generator set will need to be operating at a slightly different frequency than the bus until it is synchronized with the bus.

The result of this is that from the instant that the generator set is physically connected to the system bus until the load sharing controls can readjust the load sharing in the system there can be unbalance in the load sharing in the system. Reverse (kW) power protection systems must be set up to ignore this normal condition. (For more information on reverse power protection see **Chapter 6 on page 169**.)

Some synchronizers allow adjustments to force a generator set to approach synchronization from a higher speed than the system bus, or from a lower speed. If the generator set is operating at a higher speed than the bus at the instant of paralleling it will pick up excess load, potentially causing a reverse power condition in other machines in the system. If it is operating at lower frequency, it will absorb kW until the load sharing system can correct the imbalance. Consequently, it is desirable to adjust systems that use slip frequency synchronizing to force a synchronizing generator set to operate at a slightly higher frequency than the system bus.

Some synchronizers include voltage matching capability in addition to their core phase angle matching function. While this function is not required in order to safely parallel in isolated bus applications because most voltage regulators will maintain voltage of a generator set at a very constant value over time, it does reduce the reactive power flow that results at the instant of paralleling with mismatched voltage. Note that with some older analog control systems voltage adjustment can be controlled to only to within plus or minus about 5%, so some out of balance will occur. Voltage matching (especially when using motorized potentiometers for adjustment) can significantly delay the synchronizing process.

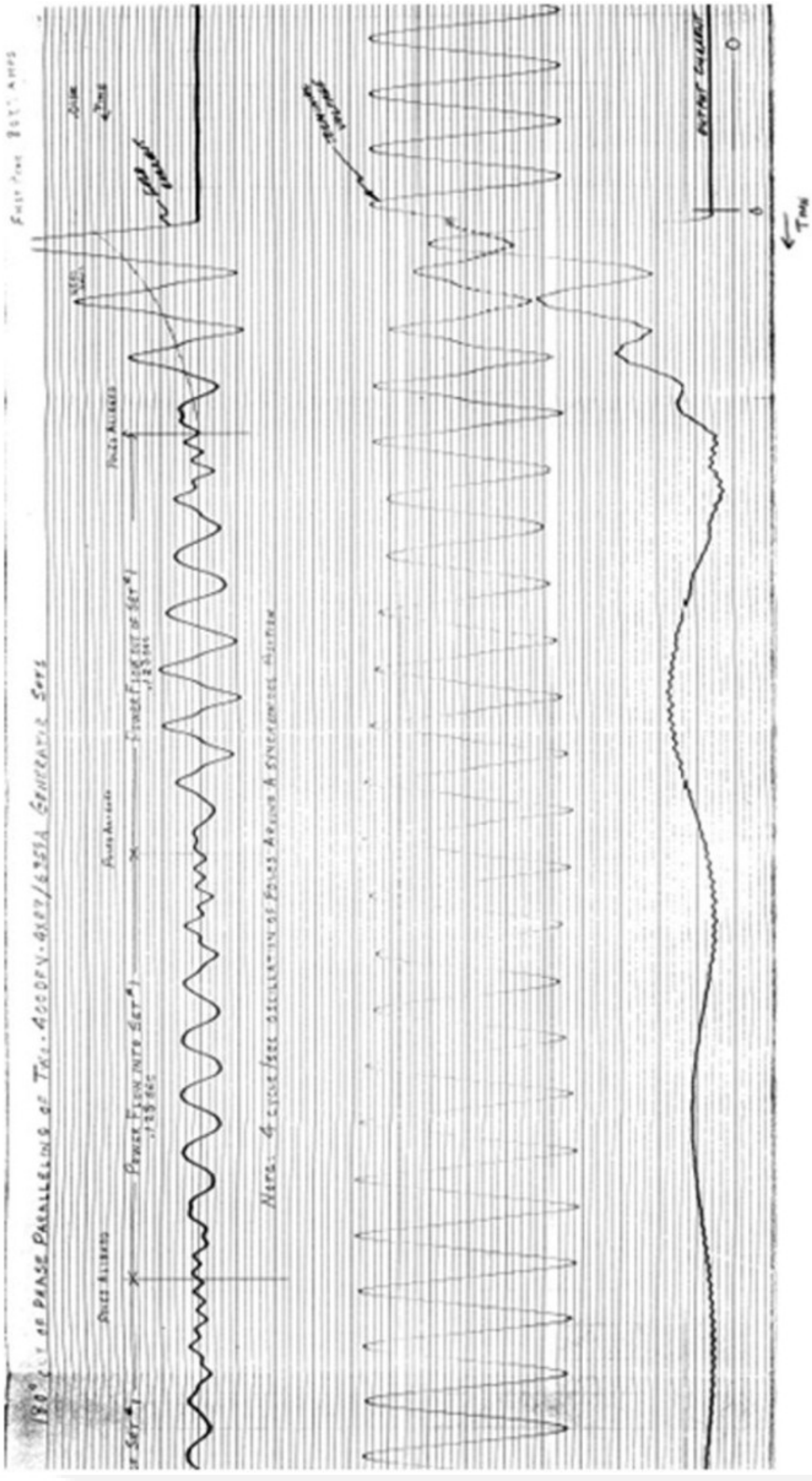


FIGURE 11. OSCILLOGRAPHIC TRACING

The figure above shows an oscillographic tracing showing the impact of out of phase paralleling on the output current, voltage, and field current of a 400 kW generator set. See Section 6.5.2.16 on page 188 for more information on out of phase paralleling

Voltage matching, however, is critical to utility paralleling applications, since utility voltage can vary dramatically as system loads change. If two sources are connected in with dissimilar voltages, current will flow between the sources until the load share or load govern system can correct the excitation system levels. These current levels can be high enough to trip protective devices.

Synchronizers provided with emergency generator systems are required to have a “dead bus” capability. This refers to the ability of the synchronizer to close the paralleling breaker when the bus is sensed to be operating at zero voltage level. Without dead bus closing capability, no generator set would be allowed to close to the bus. This capability does lead to the need for another protective function, which allows only one generator to be the first to close to a dead bus. See **Section 3.4.4 on page 33** and **Section 6.5.2.16 on page 188** for more information on this.

The performance of the synchronizer in a paralleling system is important to the overall performance of the system. If a synchronizer is slow or fails to perform in some way, the system cannot serve all the loads in the system because all the generators cannot close to the bus. As noted previously, the synchronizer often operates through the load sharing control system to slightly change the fuel rate on the engine to either “catch up” or “slow down” to force voltage zero-crossing points to match. Thus, the synchronizer can make a marginally stable governor or ILS system unstable. This is a particular concern in emergency paralleling applications, when one recognizes that the synchronizer is normally operating when the engine is cold and at its most unstable condition. It is important that a paralleling system is tested in cold start conditions (all the engines are at the temperature which would be present after several days of no operation, with only their coolant heaters operating).

Synchronizers commonly include adjustments for phase angle window and time within the window. When the generator set is in the prescribed window for a predetermined period of time, a generator set is allowed to close to the bus. The exact set point for the synchronizing window is best determined based on recommendations from the generator set manufacturer. The settings should recognize that the narrower the window and the longer the time requirement to be in the window, the longer it will take to synchronize. On the other hand, these two parameters will also directly affect the surge loads on the generator set at the instant of breaker closure. Common settings for generator set to generator set paralleling require operation within a 20 degree window for at least 0.5 seconds prior to a breaker close command. When synchronizing to a utility source, sync check windows will need to be significantly tighter. Usual settings are plus or minus not more than 10 electrical degrees. Generator sets used in paralleling applications should be prototype tested to validate their ability to synchronize reliably within a specific permissive window.

A synchronizer in a digital control system should be capable of exactly matching the frequency and voltage of a generator set coming on to a live bus, and allowing paralleling to occur with no more than a 5 degree difference in the oncoming source and the bus phase angle within less than 5 seconds, when the bus and the oncoming generator are stable.

The speed of synchronizing varies considerably with the type of generator set, the condition of the generator set, and the quality and accuracy of the synchronizing set up. Engines that are very stable and can move fuel quickly and stably into combustion will synchronize much faster than less stable engines. For example, a typical diesel engine will synchronize more quickly than a carbureted natural gas-fueled engine. Emission-controlled engines are typically able to synchronize faster than hydro-mechanically fueled engines.

3.4.3.1 Synchronizer Types

Automatic synchronizers usually have one of two different designs, slip frequency or phase lock loop.

3.4.3.1.1 Slip Frequency Synchronizer

In a slip frequency synchronizer, the oncoming generator is operating at a frequency that is slightly higher than the bus reference frequency.

Note in the figure below that the generator frequency is shorter time period, so even though it is not always aligned with the bus, it does constantly come in and out of synchronization.

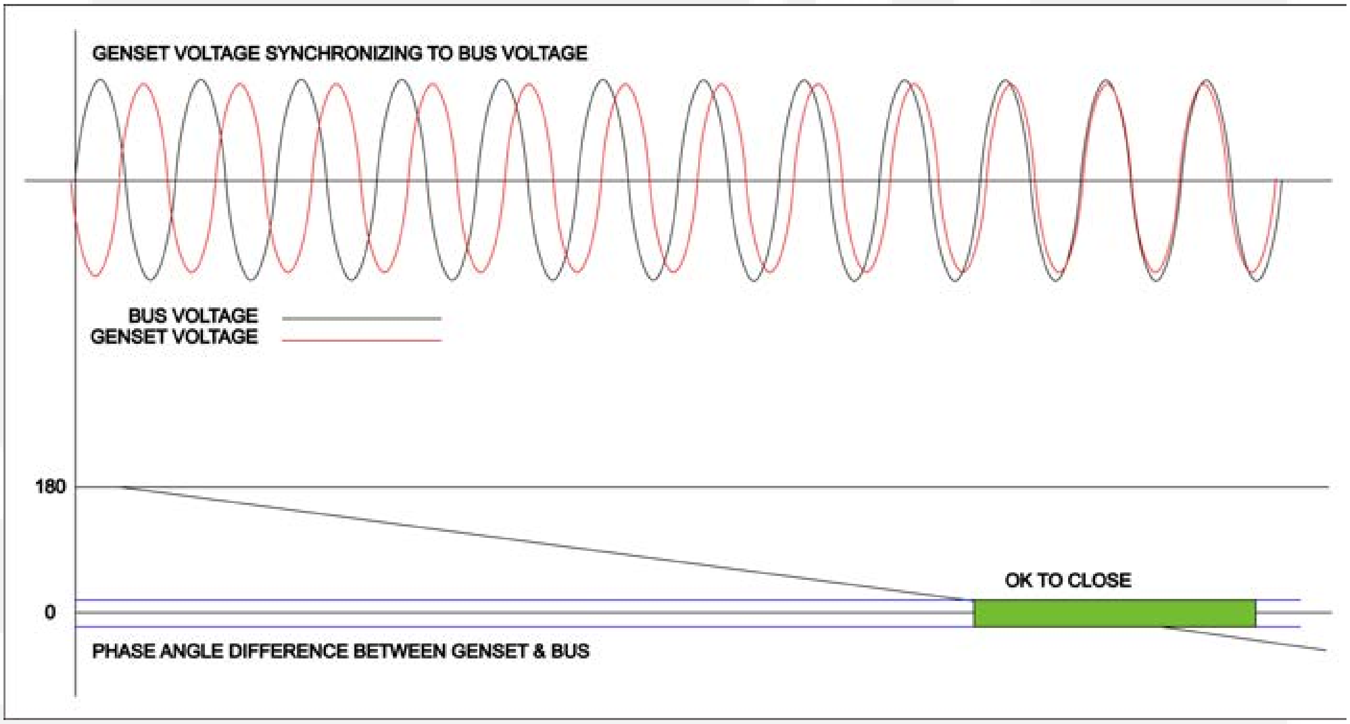


FIGURE 12. SLIP FREQUENCY SYNCHRONIZER OPERATION

The sine waves at the top of the illustration in the figure above show a typical generator and bus voltage. Note that frequency of bus (black line) is constant and the frequency of generator set (red line) is constant but slightly higher than the bus. The frequency difference is ok, because when generator set frequency is higher (shorter cycle time), it “catches up” to bus over time. However, it will eventually go out of phase again due to this same frequency difference. Note how rate of change of phase difference line is a constant slope over time.

The sync-check window (shown by blue lines) shows upper and lower acceptance limits for out of phase acceptability. Remember that if the frequency of the two sources is different, they will constantly go in and out of synchronization. If the frequency difference is small, they will slowly synchronize but stay in the sync check window for a long period of time. If the frequency difference is large, they will quickly synchronize, but will not stay in the window for very long—maybe not long enough to safely close the generator breaker. Also, if the machines are at the same frequency, they will not move toward synchronization at all. Typical frequency difference between sources in a slip frequency synchronizer is set to 0.1 hertz. This leads to the generator sets going into synchronization once every 10 seconds with a 20 degree window. For greater accuracy, frequency difference can be set to 0.5 hertz, which will result in synchronizing every 20 seconds with a 10 degree window.

Slip frequency synchronizing can be used in both automatic and manual type synchronizing systems. It is also commonly used in closed transition transfer switches.

In manual synchronizing (which is similar to slip frequency synchronizing) the operator will typically adjust the speed of the oncoming generator set slightly different than the bus (0.1 hz is common), and manually close the breaker when the sync check acceptance parameters are met. In closed transition transfer switches, the generator set frequency must be different than the utility frequency in order for the systems to synchronize. Most Closed transition transfer switches depend on the generator set to be pre-adjusted to a suitable frequency that is different from the utility for this to be achieved.

In all cases, if the generator set voltage does not match the utility voltage, there will be a current flow induced between the sources at the instant of synchronizing. In active paralleling systems this is corrected by operation of the load sharing control system. In manual systems, the operator must make adjustments to “frequency” and “voltage” in order to balance load sharing. In fast (hard) closed transition ATS, the duration of current flow is so short it usually does not cause problems. However, it is desirable to adjust the generator set so that it normally operates at a higher voltage than the utility/mains service, so that on connecting it will absorb vars rather than forcing the utility to absorb vars, which might be cause other protective relays to operate.

3.4.3.1.2 Phase Lock Loop Synchronizer

Another synchronizer type is called a Phase Lock Loop synchronizer (see figure below). The sine waves at the top of the chart show a typical generator and bus voltage. Note that frequency of generator set is varying, and frequency of bus is constant. (It actually is usually changing a bit, but for simplicity we are showing it as constant.) Peak voltage of generator set and bus is different at the start but that is ok. Here we show impact of voltage matching during synchronizing, which makes the peaks of both waveforms match in magnitude.

Note below that the generator frequency and voltage starts at a different level, but is changed to match bus conditions, and held in synchronization until paralleled.

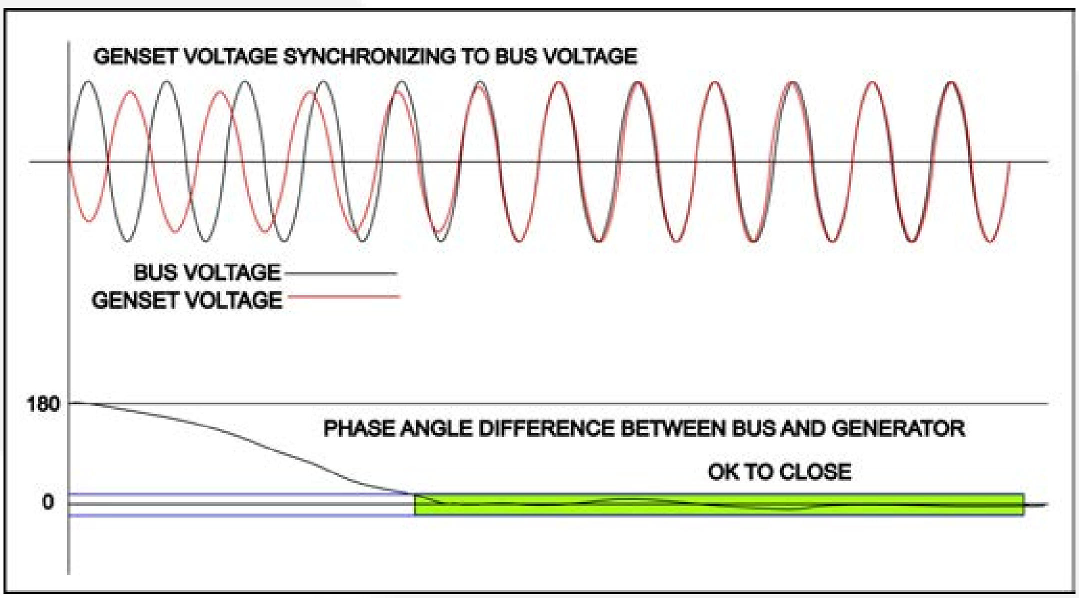


FIGURE 13. PHASE LOCK LOOP SYNCHRONIZER OPERATION.

Note that the generator set frequency is forced to same time period as bus, and is held there. The phase angle difference is not a constant slope, but changes quickly in either direction as the generator set is actively controlled to match the bus. Note also that the time in the sync check window is much longer. Generator set will stay synchronized for a long time, as long as generator set and bus frequency are not changed. It is common for load changes on a system bus to cause sudden change in phase angle difference, which effectively makes the sync process start over.

The sync check window (shown by blue lines) shows upper and lower acceptance limits for out of phase acceptability.

When engines are difficult to control and cannot reliably maintain constant speed, sometimes slip-frequency synchronizing is used. In this arrangement the engine speed is constantly but slowly raised and lowered to force the generator set to synchronize for a short time with the bus.

A synchronizer will typically be set up to monitor one phase of the generator set and the bus, but it is highly desirable for a synchronizer to monitor all three phases, especially in utility paralleling applications. This prevents catastrophic generator set damage that would occur if the machines were accidentally connected with dissimilar phase sequence.

3.4.4 Selection of First Generator Set to Close-to-Bus

In an automatic multiple generator set paralleling system operating in an isolated bus mode for emergency standby applications, all the generator sets are typically commanded to start simultaneously and multiple generator sets can be ready to close to the bus at the same time. Because there is no bus voltage reference available at this point in time (no generators are connected to the bus), the generator sets are not synchronized with one another. One generator set is required to close to the bus to provide a voltage reference for all the other generator sets in the system to synchronize and close to the bus.

Several control problems are inherent in this portion of the system design. First, each generator set must determine whether or not it is ready to accept load. Then, presuming that it is desired to get the system started automatically and as fast as possible, the system must determine which generator set will be designated to be the first to close to the bus (usually first machine at or near rated voltage and frequency). With that generator set selected, the other generators in the system must be prevented from closing to the bus until the first generator set is connected. Means must be included to disconnect the designated first generator set connected to be positively disconnected, if it cannot be verified that it successfully closed to the bus. Finally, all other generator sets in the system must check for phase sequence matching [usually done with a phase sequence voltage relay (47)], start their synchronizers, and connect at the appropriate time.

Various manufacturers have differing systems for providing these functions, and they differ in effectiveness in meeting all the system requirements. The selection of the first generator to close to the bus is usually accomplished by communication between the generator set controls. For example, the generator sets may employ a token passing scheme in which only the generator set with the token may close to the bus. When the generator set receives the token it will close to the bus if it is operating at rated speed and voltage. If not it will pass the token to the next generator set.

3.4.5 Generator Set Protective Functions

The control systems provided by different manufacturers include different protective relaying packages depending on the manufacturer's preferences and the requirements of the project specifications. It should be noted that addition of protective devices can affect system reliability, so careful selection of function and settings with a clear understanding of equipment purpose is necessary to minimize this impact. Generator sets used in emergency applications would generally have few protective devices less conservatively set than generator sets in prime power applications. It should also be recognized that the settings and functions of protective devices in a paralleling control are related to generator set protection, so settings are likely to be different than bus or utility protection, even if the same functions are provided.

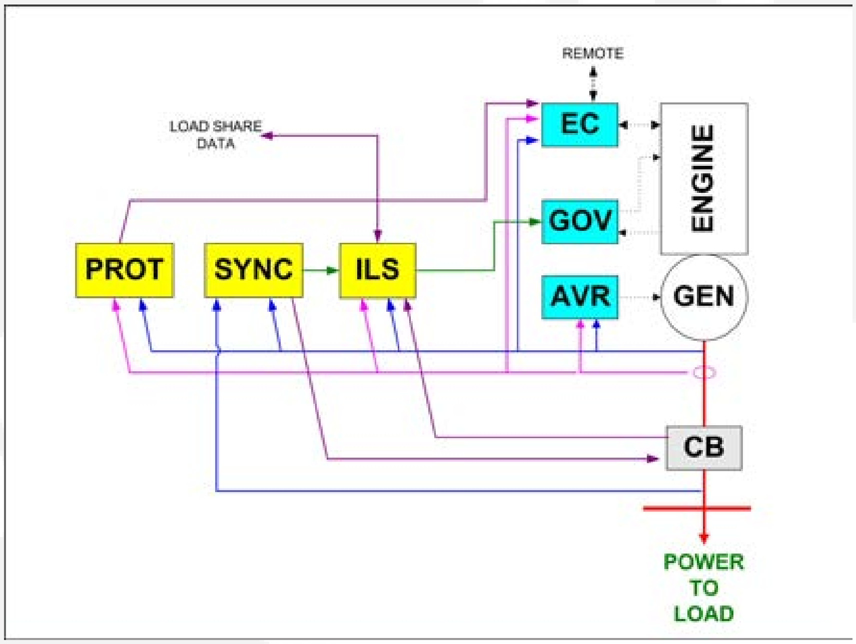


FIGURE 14. PROTECTIVE FUNCTIONS ADDED TO GENERATOR SET CONTROL.

Two protective devices are generally required in paralleling systems for generator set protection: a reverse power relay (ANSI device 32) and a loss of field or reverse VAR relay (ANSI device 40).

3.4.5.1 Reverse Power Relay

The reverse power relay monitors the power flow for magnitude and direction. If the generator set is paralleled to the system bus and for some reason loses the ability to produce real kW power output, the synchronous alternator, which is excited by the system bus, becomes, in effect, a synchronous motor rotating the engine from system bus power. The alternator can damage the engine by this action as well as putting an incremental load on the system bus. By monitoring the power flow and direction from the machine the reverse power relay will sense when the failure has occurred, trip the paralleling breaker and switch off the generator set.

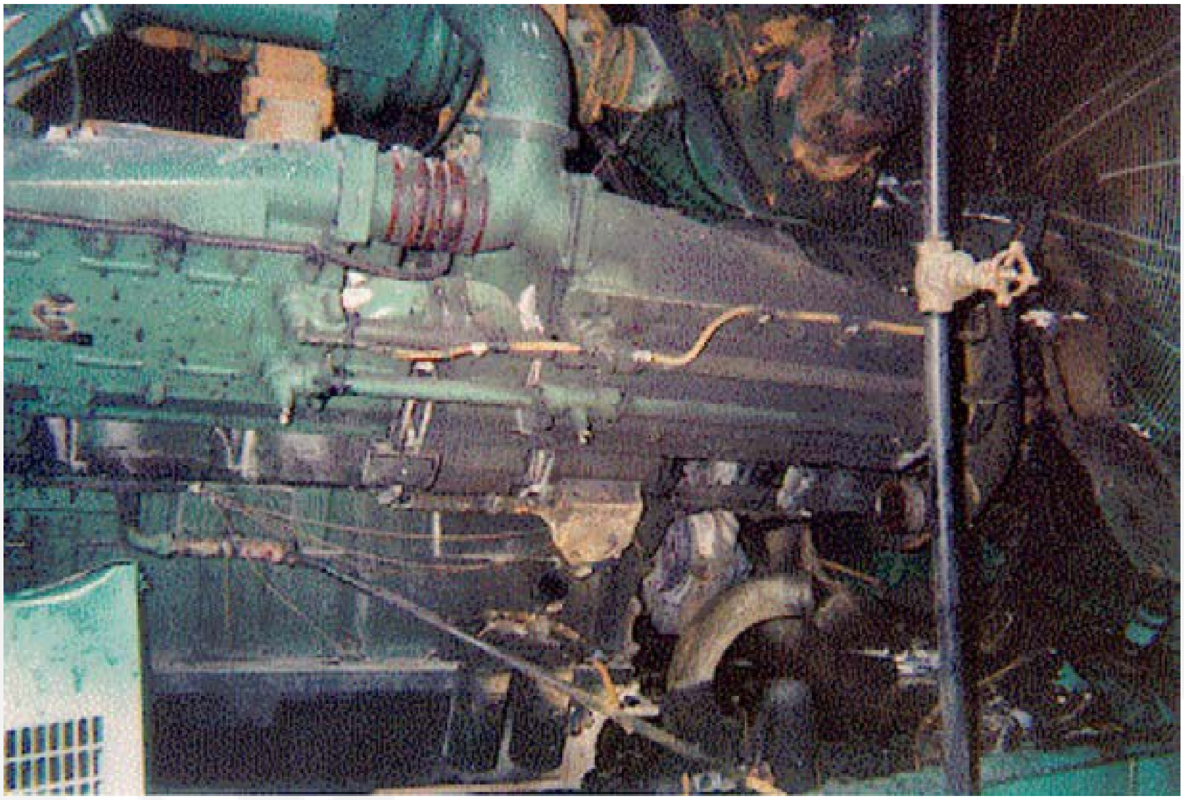


FIGURE 15. CATASTROPHIC DAMAGE TO AN ENGINE THAT WAS REVERSE-POWERED.

Reverse power relay settings are usually set based on the engine motoring load. Motoring load is the horsepower required to rotate the engine when the engine is producing no useful output. The magnitude of load present varies with the age of the engine (new engines have typically higher motoring load than older engines). If the reverse power limit is set to a value greater than then motoring limit, the reverse power function will never operate. If it is set too low, the generator set may nuisance trip during transient loading conditions, especially after breaker closure. Common settings are to operate when reverse power exceeds 5-7% of the engine rating for more than approximately 3 to 10 seconds. Tighter settings for magnitude or time delay may cause nuisance reverse power trips. The engine manufacturer should recommend the proper reverse power limit based on the motoring power required to rotate that engine with zero combustion or fuel flow. This value varies by engine, and as noted, over time as the engine wears. See **Chapter 6 on page 169** for further information on protection settings for generator sets in paralleling applications.

3.4.5.2 Reverse Var or Loss of Field

The reverse VAR or loss of field relay provides protection analogous to reverse power, but against excitation system failures while the generator set is paralleled to the system bus. Functions of specific devices vary, but in general the protective function will calculate kVAR load and direction, and operate when reverse kVAR level reaches a preset point. Alternator protection requirements vary considerably with specific alternators, but common settings are not more than 20% of rated kVAR for a time delay of 10-30 seconds. Capacitive (leading power factor) loads can cause nuisance tripping of reverse VAR relaying if the protection is set at levels which are too restrictive. This means that for some applications, such as data centers, a careful analysis of the var levels generated by the load devices during the start up sequence of the system is required when paralleled generators provide emergency power.

More information on this topic is provided in **Section 6.5 on page 172**. A list of ANSI standard abbreviations for protective functions is provided in the **Section 8.6 on page 259**.

3.4.6 Metering and Manual Controls

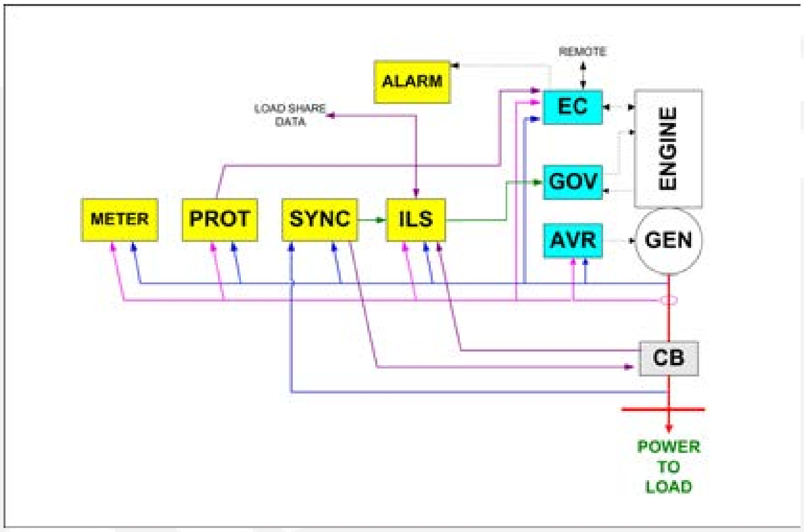


FIGURE 16. METERING AND MANUAL CONTROL LOGICAL CONNECTIONS TO BALANCE OF GENERATOR SET CONTROL.

Metering and manual controls are provided in most paralleling control systems to allow proper set up of the system during commissioning, facilitate service, provide manual system operation capability, and to allow the operator to view generator and system status. In many cases, the AC metering functions are integrated together, and the manual controls are integrated into other control hardware.

Most generator sets are provided with four AC meters when they are paralleled: 3-phase AC voltmeter, ammeter, frequency meter, and KW meter. The voltmeter and frequency meter are used in manual paralleling operation to help the operator adjust the generator set for synchronous conditions before closing the paralleling breaker. The KW and ammeters are used to set up the load sharing control systems of the generator set. Along with the meters, there are generally phase selector switches.

A power factor meter is highly desirable for easier adjustment of kVAR load sharing systems. The generator set ammeters will detect current flow, but the power factor meter will tell the operator which generator set is overexcited compared to the other. Analog metering is desirable for generator metering when paralleling, because meter movement can be used as part of service diagnostic procedures.

Often metering equipment includes synchronizing lamps and/or a synchroscope for use in manually paralleling the generator set to the system bus. The other controls that may be necessary for manual paralleling include a manual frequency and voltage control devices. (NOTE: adjustments to the frequency and voltage prior to paralleling will necessitate readjustments in the load sharing between generator sets, once they are paralleled.) Note also that the manual paralleling provisions are optimally located close to the generator set, because when manual synchronizing is most needed (during a failure of the automatic synchronizing process) the problems causing the condition are likely driven by engine problems. Some systems have multiple locations for manual operation for the convenience of operators and effectiveness of service.

Most generator sets also have mode selection switches to allow operation of the system in manual or automatic modes, and manual breaker control switches. Again, these are used as a fall-back control system in the event that the automatic control system fails. They are also used in system startup and service work.

NOTE: The group of metering and controls that monitors and controls a specific generator set is called a *paralleling control panel*. In a paralleling system, there is generally one paralleling control for each generator set in the system, and a master (totalizing) control, which acts as the interface between the paralleling controls and the facility electrical system. Master (totalizing) control panels commonly have total power system metering, load adding and shedding controls, system protective devices, and manual system control provisions. The functions of the master control depend on the needs of the application, and are less standardized than the paralleling control functions. See Section 3.9 on page 43 later in this section for more information.

3.4.7 Utility (Mains) Paralleling Functions (Load Govern)

This illustration below shows generator set control with load govern functions added and closed transition power transfer and protection functions for the utility, which may or may not be located in the generator set control.

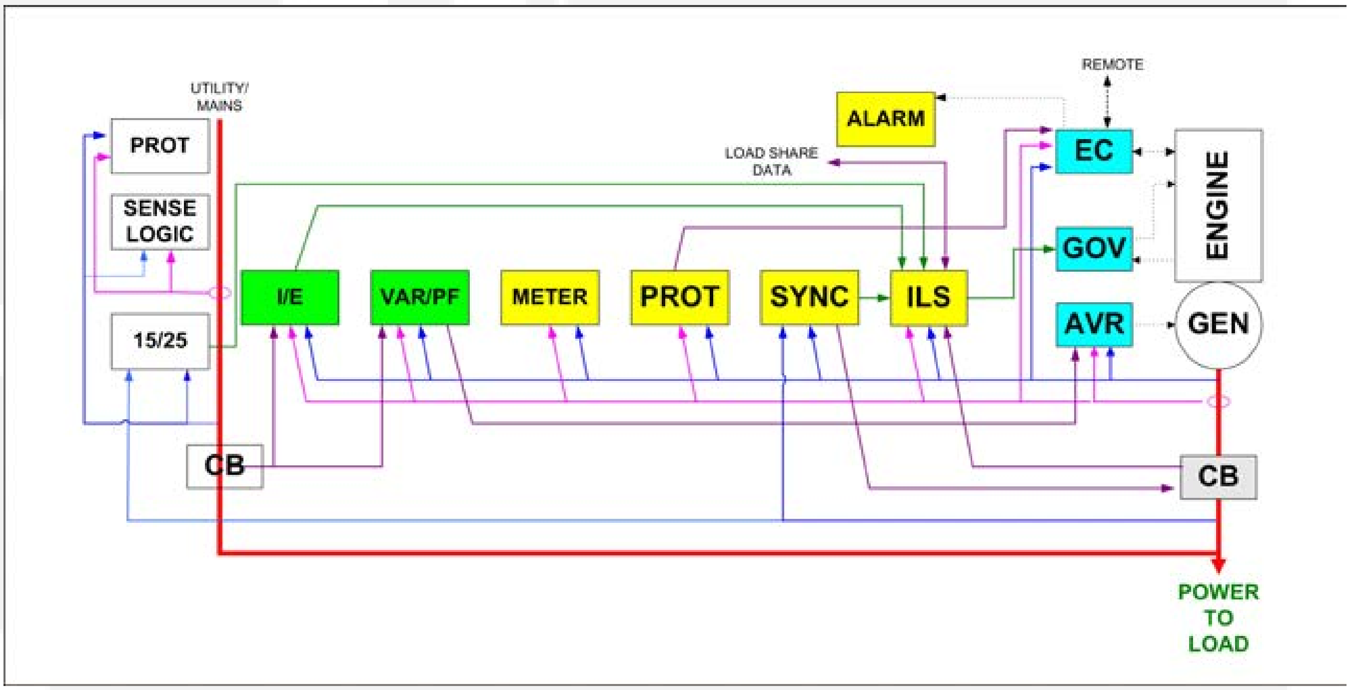


FIGURE 17. GENERATOR SET CONTROL WITH LOAD GOVERN FUNCTIONS ADDED

Generator sets that are used in utility paralleling applications need two more functions in order to provide necessary operation, an import/export control (shown as I/E in the above), for KW regulation and a var/power factor control (Var/PF). These controls are necessary because the generator set cannot greatly affect the voltage and frequency of the utility; and the voltage on the utility is not constant and proportional to load, as it is on a generator set. This drives the need for the additional function that provides fuel rate control strictly as a function of kW load, and excitation control as a function of kVAR load.

Both the import/export control and the VAR/power factor control will accept a signal which “tells” them that the generator set is paralleled to the utility. Usually this signal is derived from breaker position indicating contacts. From that point on the controls will force the generator set to produce a measured kW or kVAR output, rather than attempting to share load interactively with other generator sets in the system.

Note also that external devices can be used to force the system to provide variable level output, whether it is needed for ramping functions, or to meet requirements for peak shaving versus base loading (which can be done without an external signal).

Import/export controls for the kW output of a generator set can operate in an active load control state, or may operate in droop when the utility (mains) frequency is very constant. With active import/export control systems, enabling the “load govern” (utility parallel) state will result in the control system effectively ignoring the frequency of the system over a broad range, and regulate the fuel control system based on calculated kW. With droop systems, the generator set is switched from isochronous load share operation when paralleled to other machines, to droop mode when paralleled to the utility (mains) service. When switched to droop, the generator set will operate at a fixed kW output.

Var/PF control systems are always operated in active control modes, because the voltage will vary considerably in most applications, making droop systems ineffective. (With a droop control system, changes in the monitored state, in this case-voltage, will cause a change in load. So, in order to maintain a stable output, the utility (mains) voltage reference would need to be very constant, and it nearly never is.) Operation of a generation set in reactive droop while paralleled with the utility can easily cause overload of the alternator, nuisance tripping of paralleling breakers, and potentially alternator damage due to pole-slipping.

Import/Export controls can be provided as separate components or functions for each generator set, or may be provided in the form of an individual control to provide import/export functions for the entire system plus an individual control for the system var/PF control functions. In general, suppliers determine which system architecture is used for their equipment. The distributed logic controls provided for each generator set are probably incrementally more reliable, because a single component failure will not disable kW or kVAR control functions for the system.

Finally, note that when multiple generators are paralleled on a common bus and must be paralleled with the utility/mains service a master synchronizer is needed to drive all the generators simultaneously into synchronization. More information on that function is later in this Section 3.7 on page 41.

3.5 Paralleling Control Hardware Options

The hardware provided for a specific application depends on the requirements of the application. If the application does not demand fast synchronizing or isochronous frequency control, the paralleling control can be composed of mechanical governing systems (if emissions controls are not required for the engine) and manual paralleling controls. Some examples of this are shown in Section 3.13.2 on page 52. If the application requires isochronous frequency control, then the paralleling control can include either analog control systems, or digital controls. Analog control systems are typically composed of individual control components for each control function. The control electronics are often provided by different suppliers, depending on the manufacturer’s or specifier’s preferences. Analog automatic control systems have been available from the inception of paralleling, but in spite of this, the service of this equipment is not easy, due to the complexity of the wiring, the unique nature of each site and the wide variation in interconnecting wiring and physical configuration of the equipment. Analog control systems typically require more highly trained operators, since direct control of the fuel and excitation systems can result in misoperation that can cause catastrophic equipment failure.

FIGURE 18. PARALLELING CONTROL PANELS WITH TRADITIONAL METERS AND SWITCHES.

Digital control systems have been available for paralleling control functions since the mid-1990s. Digital controls are microprocessor-based, and often integrate many, or even all of the paralleling control functions (see figure below). While this may seem surprising, it is actually not unreasonable when one considers that the cost of a digital control system is heavily dependent on the costs of the inputs and outputs for the control system. Notice that in spite of the many functions required of the control system (**Figure 17 on page 37**), the functions are based on sensing only a few functions, such as voltage, current, breaker position; and providing breaker controls. The advantages of digital controls include easier set up and adjustment, higher reliability, better serviceability, and lower space requirements. They are easier to operate confidently, since the operator interfaces provide more information and the protective capability of the equipment is not lost during “manual” operations.

FIGURE 19. DIGITAL GENERATOR PARALLELING CONTROL. SIMILAR FUNCTIONS AS THE PARALLELING CONTROL SHOWN IN FIGURE 18.

Paralleling control systems typically include a voltmeter, ammeter, kW meter, and frequency meter, and often include a kVar or power factor meter. Metering can be either analog, or digital, or both. Analog metering is easier to use for set up and adjustment, and is useful when diagnosing system problems, as trends and stability are easier to see on analog meter sets than on digital meters. However, digital meters are much easier for operators to use for recording data.

It is tempting to prefer digital meters, because they seem to give a more precise indication of metered values. However, it should be recognized that they may be no more accurate than analog instruments, and attempts to precisely adjust specific values can upset system settings, especially load sharing controls.

The voltmeter and frequency meter are often used in conjunction with manual synchronizing equipment for precise manual paralleling. Remember that if these parameters are adjusted during manual paralleling, adjustment of load sharing will generally be required after the generator is connected to the bus. The kW and kVar metering are used in the set up and adjustment of the load sharing control systems.

Generator set engine control systems can be analog, digital, or PLC-based systems. Analog systems are often considered easiest to service, but are prone to a wide range of misoperation caused by various component failures and misadjustments. So, they are actually much more complex to service and differences from site to site make training for consistent repair processes more difficult. They are limited in their functionality and flexibility.

Digital controls often have many more functions, and can provide more flexibility, and are usually more reliable than other controls. They are easy to design to deal with the widely varying control voltage supply on a generator set. (When the starter on a generator is engaged, voltage will often dip to less than 50% of nominal condition level, disrupting controls that are not specifically designed to deal with that condition.) Digital controls are often (but not always) designed for direct mounting on the generator set and to withstand the rigors of that environment, such as temperature extremes, dust, moisture, etc.

Conventional PLC-based control systems are undesirable for generator controls, especially when mounted on a generator set, regardless of the control voltage protection added to the system because of their limited environmental protection and sensitivity to control voltage variations. It should also be recognized that the interconnecting wiring between the PLC and generator set can be a source of problems and reduce reliability.

With the advent of emission-controlled engines it has become common to integrate engine control and governing control functions, because the governing function requires inputs from the engine control for values such as engine temperatures and pressures in order to maintain the ability of the engine to meet environmental requirements for exhaust contaminants.

3.6 Adjustments/Tuning

Paralleling control systems often include voltage and frequency adjustment provisions which are accessible to an operator. These adjustments are used in the manual paralleling process to match the frequency and voltage of the oncoming generator set to the bus. It is important to note that these adjustments directly affect real and reactive load sharing, so once the generator is closed to the bus, the load sharing must be readjusted to be properly set up. Note that in order to balance the reactive load sharing, there must be some stable inductive loads available.

Many operators are confused by these controls because once the paralleling breaker closes they no longer directly affect frequency and voltage, but as discussed previously (**Section 3.4.2 on page 22**), they directly control real and reactive load sharing.

The frequency and voltage of the bus can be manipulated if all the machines are adjusted up or down to the same level for the same function.

Paralleling control systems can have a wide variety of service adjustments. These vary by manufacturer and equipment type, and the exact adjustments are beyond the scope of this document. They include adjustment of synchronizing windows and gains, load govern levels and gains, and set points for protective functions. It is important that these be adjusted by skilled technicians, and not tackled by untrained persons, since misadjustments can result in anything from misoperation to catastrophic failure of a generator set (**Figure 14 on page 34**). Some systems, particularly digital control systems, utilize PC-based service tools, or protect the service adjustments in the system by passwords and other means.

3.7 Power Transfer Control System

Power transfer control systems are necessary in applications where more than one source can serve the system loads. In some system designs the Power Transfer Control System is integrated in automatic transfer switches, in others, within the master control; but it is treated separately here for clarity. Leaving the power transfer control separate from the master control is probably more reliable because each transfer point will operate like an independent autonomous transfer switch, which is unaffected by failures in other parts of the system.

See **Chapter 5 on page 105** for more detailed information on power transfer systems.

If it is necessary to be operate the system automatically, the following control system functions are necessary:

- Voltage sensing (normal source and alternator source [or sources]) is required to detect availability of sources. Voltage sensing may be either single phase sensing or all-phase sensing, and may be either line to neutral or line to line sensing. The only advantage of single phase sensing is that it is less expensive than all-phase sensing. Individual phase/line to neutral sensing is more likely to catch loss of a single phase than line to line sensing arrangements. Close differential voltage sensing, which is designed to operate reliably with very close differences between drop out and pick up voltages also helps to maintain power quality in a facility, by detecting voltage sags more reliably than conventional sensing.
- Timing functions (start, stop, transfer, retransfer, open time [e.g., controlling the speed of operation of the transfer devices], overlap time [the period of time when two sources are paralleled together in a closed transition sequence], fail to disconnect, etc.).
- Logical functions such as transfer inhibit (allowing an external device to prevent transfer) or load shed (use of an external device to cause the transfer system to disconnect from a source to intentionally disconnect loads).
- Metering and status displays: The minimum information presented is probably source available and source connected indication), but other common functions include indication of operating in the test mode, and the ability to make adjustments in control system set points.
- Exercising functions (setting up the system to automatically exercise at certain calendar dates and times)
- Operator adjustments (set points for timing, source availability definition).

When the power transfer mechanism (transfer switch or breaker pair) is capable of independent control of the two sets of contacts in each transfer point, the sequence of operation can be open transition, fast closed transition, or ramping closed transition. It may also include peak shaving or base load functions. These are described in more detail in Chapter 7 on page 203. Open transition is easiest to accomplish and is almost universally accepted around the world. Closed transition operating modes require approval of the utility/mains service provider. In general, facility operators like closed transition operation because, done properly, it will eliminate voltage and frequency transients that can be disruptive to operation of certain types of loads.

As with the paralleling controls, the designer has the option to specify systems designed using components from multiple suppliers, or integrated control system equipment from a single supplier. In general, integrated control systems will be less expensive, consume less physical space, and will be more reliable. A critical factor in the decision is also the ability of the system to be serviced over the life of the facility, which may be an overwhelming factor in the final hardware decision.

NOTE: More information on power transfer systems is discussed in Cummins Power Generation Application Manual T-011, which is available at www.cumminspower.com.

NOTE: See white papers on this topic: PT-7016, ATS Set-up Considerations, which is available at www.cumminspower.com.

3.8 Utility (Mains) Paralleling Functions

Systems which automatically synchronize multiple generator sets to the utility must also include a master synchronizer (may also be called “bus synchronizer”).

The function of the master synchronizer (device 15/25 in **Figure 17 on page 37**) is to compare the generator set bus voltage and frequency to the utility bus voltage and frequency. Like the generator set synchronizer previously discussed, the control then causes the generator set (or sets) fuel rate and excitation levels to be simultaneously adjusted to match the utility signal conditions. When the conditions are within an acceptance window, a breaker is closed to connect the two systems together. Unlike generator synchronizers, it is very critical that a master synchronizer precisely adjusts the generator set bus voltage while synchronizing to prevent nuisance breaker tripping at the instant of paralleling the two sources.

In general, once the two systems are interconnected the load is ramped to one of the sources, again by either simultaneously increasing the fuel and excitation levels to increase real and reactive load on the generator sets, or by decreasing those values.

The actual mechanism used to change fuel rate and excitation level varies by control system manufacturer.

See **Section 7.5 on page 231** and **Section 3.5 on page 38** for more information about system requirements for utility paralleling applications.

3.9 System Level Controls

3.9.1 Master Control Systems for Emergency/Standby Applications

While paralleling control systems vary little with the application, master control systems can vary widely in functionality depending on the needs of the application. However, the variation is more related to the magnitude of control needed for specific functions than the number of functions. The core reason for this is that while the primary interface for a paralleling control is to a generator set, and the control of those functions is the same for every application, a master control interfaces the paralleling controls to the specific facility where it is installed. So, the facility needs, which vary greatly from site to site, drive different needs for master controls. Consequently, while there is little a system designer needs to do in terms of defining functions necessary for automatic paralleling of generator sets, there is clear need for the designer to take a leading role in defining system operation needs. Some common questions that need resolution for successful completion of a project include:

- What mechanisms are to be used for transfer of power from normal source (or sources) to the generator sets?
- What is the load adding sequence?
- What devices are used for load addition?
- What is the load shedding sequence?
- What devices are to be used for load shedding?
- Is there a need for load demand? (i.e., the need for extended hours of operation that may make fuel consumption an important issue for the site.)

- What sort of operator interface is needed? What functions should be included? What manual operation capability should be provided?
- Where should the operator interface be located? (It may be desirable to have an operator interface in more than one location.)
- Is there value in having remote monitoring or notification of system status to personnel in the facility or a servicing agent? If so, what is the information to be transferred, and how?

See **Chapter 7 on page 203** for more information on load control systems and load demand.

The master control acts as the interface between the generator paralleling controls and the rest of the system. An on-site power system that utilizes paralleled generator sets is different from a single generator set system in that with a single generator set, once you have the generator set available, you immediately have access to the full output of the generator set. Consequently, there may be little attention given to highly controlled load addition sequences. With paralleled generator sets, one generator set closes to the bus, and is able to provide power to the highest priority loads, and the other generator sets in the system must synchronize to the voltage reference provided by the first available generator set. This means that while the first generator set will typically be available within approximately 10 seconds after a power failure is sensed, the other generator sets may take 5 seconds or more of additional time to get to the bus. Thus, if the loads in the facility are not controlled to limit the power demanded of the first generator set to close, the first generator set can be overloaded and the system can fail.

The sequence that loads are added to the bus on a black start condition is based on the needs of the application, and may be affected by local codes and standards[2] that stipulate that certain loads must be fed first when paralleled generator sets are used.

When paralleled generator sets are used in an application, the system designer should tabulate the system loads, recording the starting power required, the steady state load level, and the time that the load can be without power without causing damage, excessive operating costs, or danger to the system or the facility occupants.

Since all the generator sets in a typical system will include individual synchronizers, they will all simultaneously synchronize to the system bus reference, and typically will close to the bus within as little as 5 seconds or as long as 20-60 seconds. Consequently, the system loads can be categorized into loads that must be served in 10 seconds or less, those that can be served later but should be served during a power failure and those that are purely optional or not served by the system.

All the loads that must be served within 10 seconds must typically be capable of being served by the first generator set that closes to the bus. If the loads exceed the capacity of a single machine, the system should be split into multiple smaller systems, or the size of the generator sets should be increased. Another alternative is to split the generator system into two independent parts, which sometimes are synchronized to each other.

The hardware required for this functionality may be as simple as a logic circuit derived from the auxiliary contacts of the paralleling breakers of the generator sets. As each circuit breaker closes, the auxiliary contact operates a relay to close additional loads to the system.

The system may be considerably more complex, and be handled by dedicated purpose controls, or a PLC and custom-written PLC program that monitors capacity available and total load levels, and adds loads until the capacity of the system is reached, or until all the generator sets are closed to the bus. These systems can even modulate loads, turning them on and off sequentially to maintain some power coverage for extended periods of time. This can work well for air conditioning or other loads that are cyclic in their operation.

[2] Codes and standards affect mostly systems that serve healthcare facilities or include emergency loads.

In addition to load adding (priority) functions, master controls typically include load shedding controls. In most systems these controls function to signal pre-specified loads to quickly be dropped if necessary to maintain service to the most critical loads.

Under-frequency is the most reliable means to sense the need for load shedding, because it compensates for the changes in engine power capability that can occur due to aging of equipment, fuel quality, engine room ambient temperature, and other factors that affect the ability of the machine to carry load. Growth of facility loads on high priority circuits is also compensated for by under frequency-based load shedding. However, under frequency condition on the generator set bus does represent an abnormal operating system, so some systems incorporate a kW-based load management system for normal operation, and an under frequency emergency load shedding scheme as a backup to the kW-based load management system.

Again, these controls may be either simple relay-based functions, or may be integrated with PLC equipment to provide more complex control schemes. It is critical that the system designer determine what loads should be shed, and if a load shed sequence is necessary, or simply a single level. A good rule of thumb is that there is a load shed level equal to the number of generator sets in the system minus one. (A 2-genset system has one load shed level; a 3-genset system has two, etc.). An individual load shed or add level can have many independent load management devices in it.

A master control can also be a good place for an operator interface to display system status, such as normal power availability (for emergency/standby applications), any system failures that are in place, status of load being served, general status of generator sets, and AC metering describing overall bus conditions. The information can be displayed in traditional format (analog AC metering and alarm lamps with labeled functions), or may be displayed in pictorial form on a graphical HMI driven by a PLC monitoring the entire system. Some systems incorporate software-based master controls that utilize one or more PC's with software to provide the operator interface function. Selection of the operator interface should be based on an evaluation of the probable level of the operators' skills, and an understanding that while dedicated purpose digital or analog metering sets, lamps, and switches provide the key information in a reliable way, a better choice in applications where unskilled operators might be required to operate the system may be a touch screen interface. Touchscreens provide data in a graphical format that is easier to understand than analog metering displays.

Another question for the operator interface to the system is where the display should be located. Commonly it is mounted on the master control panel, but with digital control systems it is possible to mount several operator panels at different places in the facility to make operation more convenient, or to provide redundant operating panels for the system. It is also possible to make monitoring of a system accessible via wireless networks and LAN or WAN interfaces, making the remote control and monitoring of the system more accessible and efficient.

A master control may include power transfer control functions. These include the ability to sense the condition of one or more normal power sources, emergency or standby power sources, and the ability to operate switches of various types to connect system loads to the most appropriate source. Conceptually, this adds transfer switch control functions to the master control, which usually operate on circuit breaker pairs to transfer power from the normal source to the generator bus source. More information on power transfer control systems can be found in **Section 3.7 on page 41**.

Finally, a master control may incorporate Load Demand functionality. A load demand system monitors the total load on the bus, the number of generators available, and starts and stops generator sets to maintain adequate capacity available without operating machines at light load levels. It is most effectively used in prime power applications where the decreases in fuel consumption that can be achieved will result in significant electric cost reduction. It is often supplied but may not be used in standby situations, because the reduction in reliability of the system may not be worth the minimum fuel savings possible.

NOTE: Unlike the paralleling control systems which are almost same for each application, the master control systems vary widely in functionality. The master control acts as the interface between the paralleling control system and the rest of the system in a specific facility. Thus depending on the facility needs, the functionality of the master control varies significantly.

3.9.2 Master Controls for Prime Power Applications

Master controls for prime power applications such as rental applications or remote prime power will generally vary significantly from emergency/standby applications, since there is often not a means available to do load control, and by definition there is no power transfer control possible. Consequently, prime power systems often do not include these functions. Similarly, there may be no need for system totalizing metering (in some cases it is desired), and no operators in place to take advantage of any system level metering that is in place.

When designing a master control system for prime power applications, it is doubly important to consider what functions are necessary, and how they should be provided based on the needs of the application.

More information on typical systems and their functions is in **Chapter 5 on page 105**.

3.10 Interaction of the Master Control in a Typical Emergency/Standby Sequence of Operation

Paralleling system designs vary considerably in how the master control interacts with the other major elements of the system. Different suppliers use different logical designs, with varying impacts on system reliability and performance. As a general rule, the most reliable system designs will have the least number of operating components between the active parts of a system. So, as a general rule, since the master control is primarily devoted to system monitoring and load sequencing, it may not have a direct part to play in the sequence of operation of a typical emergency or standby power system.

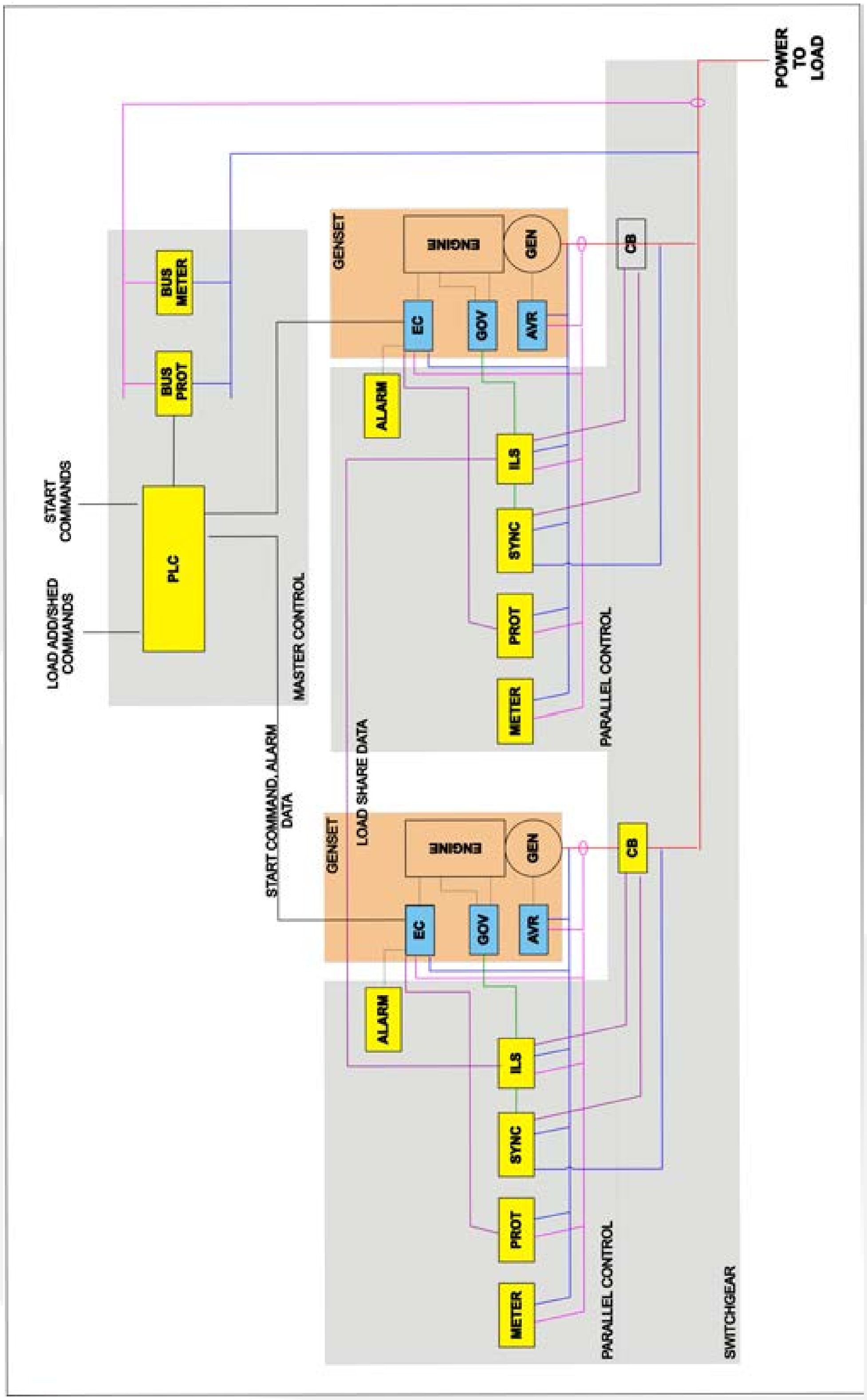


FIGURE 20. MASTER CONTROL FOR AN ISOLATED BUS PARALLELING SYSTEM SHOWING INTERFACES TO TYPICAL GENERATOR SET CONTROL BLOCKS.

Consider the situation where two generator sets are paralleled together on an isolated bus and monitored by a master control (see above **Figure 20**). The system power is transferred by a series of automatic transfer switches (not shown).

The black start sequence may be represented by the logic shown in **Figure 21** below.

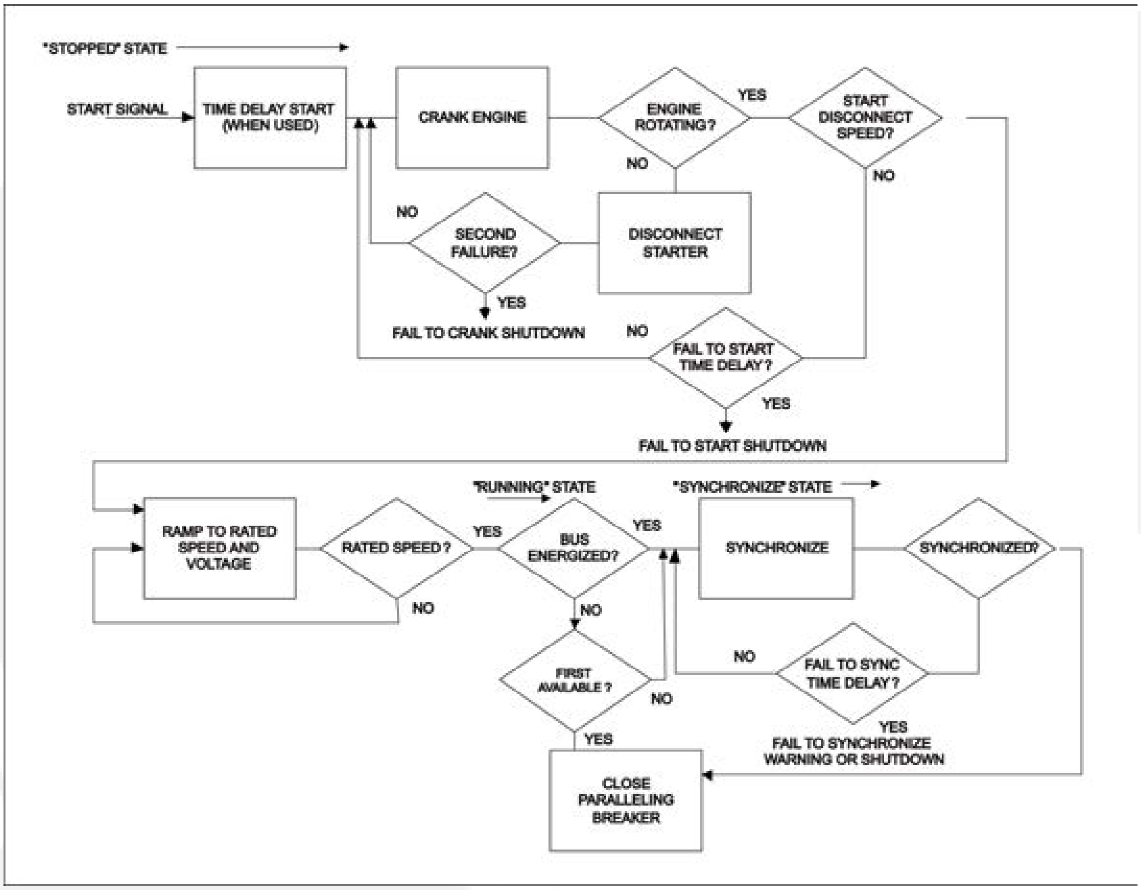


FIGURE 21. BLACK START LOGIC FOR EACH GENERATOR SET IN A MULTIPLE GENERATOR SET ISOLATED BUS SYSTEM.

Note that this logic is all contained in the generator set control system and the master control part of the system is simply providing the load add sequence in the process of putting the system on line. It would also often include load shedding capability and capacity control capability.

3.11 Master Control Hardware Options

An equipment designer developing requirements for a master control should consider:

- The need for bus totalizing metering, and the type of AC metering that is appropriate for the application. The two major options are use of analog (needle-type) meters versus digital metering displays. Analog meters are better at displaying trends and stability, but may lack the accuracy of digital meters. Digital meters are often “true RMS”, which means that they will not be disrupted by the effects of non-linear loads. Functions typically include ammeter, voltmeter, frequency meter, and kW meter. A synchroscope and synchronizing lamps with bus and generator volts and frequency may also be provided.

- The need for system status displays. The designer should evaluate what system conditions are necessary for an operator to be aware of, and what form of display of this information is most appropriate. These displays may be incandescent lamp-based, typically with colored lenses to indicate the relative level of seriousness of the information displayed; LED lamps with similar display functions (LEDs last longer but may not be as easy to see in bright light); or graphical/alphanumeric displays, that provide system status messages.
- The need for operator control of system operating modes, and means to bypass certain automatic functions. Typical mode controls for a paralleling system might include the ability to test the system in various ways (with or without load), manually control load adding and load shedding sequences, or control system transfer and retransfer sequences. These functions may be performed with rotary switches, or may be done with alphanumeric display panels with membrane switches that are directly linked to a master PLC. An entire operator interface for the system can be integrated into the system using a touchscreen panel. This has huge advantages in terms of providing detailed information in a form the operator can easily understand and use. However, it is necessary to consider and provide means for required manual operation of the system in the event the touchscreen or PLC driving the touchscreen fails.
- Some system designers prefer that manual controls bypass the core controls of the system, which are commonly PLC-based, anticipating that if the PLC fails, the manual mode would still need to be operational.

The operator interface for a master control may also include a graphical touchscreen that is coupled to a PLC that holds system data and provides graphical or pictorial information rather than simple switch and text displays see **Section 8.1 on page 235** for more information on master control functions and touchscreen features.

These systems are usually a little more expensive than more traditional operator interfaces, but display much more information in formats that are generally easier for operators to understand. If an operator is more comfortable with operation of the system and can understand clearly system status and controls, they are more likely to make good decisions during abnormal operation states.

Internal functions of a master control often include:

- Load protection devices. Multiple generator sets are unlikely to fail in a fashion that will cause an overvoltage condition. However, if a generator set has a failed sensing circuit for its voltage regulation circuit, and the generator set is the first available to close to the bus, loads could be exposed to over voltage. If multiple generator sets are on the bus, a voltage sensing failure will not result in overvoltage, but rather is more likely to result in an Overcurrent condition on the failed machine, or reverse var condition on other generator sets in the system. Because of this, and to avoid nuisance over voltage shutdowns, it is appropriate to apply overvoltage protection to each generator set in the system, so that no machine can close to the bus in an overvoltage condition. If an overvoltage condition did occur with multiple generator sets on the bus, the protection would still function to protect loads, by shutting down all the machines in the system.
- Under frequency conditions usually are the result of generator set overloads, typical system designs usually will result in system commands to shed load. As with overvoltage, it is not likely that a generator set bus will reach over frequency conditions, so this protection is not necessary for load protection.

- Load sequencing controls, to control the order that loads are added to the generator bus during black start conditions, and the sequence of load shedding, should that become necessary. In some systems, load management is managed by a facility automation system, making those functions unnecessary in the master control. See Chapter 5 on page 105 for more information on load add and shed systems.
- Load demand controls. These controls monitor the total load on the system bus, and provide a means to automatically turn generator sets on and off as a function of total system load, so that overall fuel consumption can be minimized.

Since master controls are often more customized that other parts of the system due to the need to interface to and serve a specific facility design, they often utilize programmable logic controls (PLCs) as the basis of their design. However, if system control functions are not complex, it is possible to complete many designs using traditional relay logic. This is particularly common when the paralleling system includes a small number of generator sets, and its primary use is emergency/standby (in those cases Load Demand is not likely to be needed).

The master control PLC may include redundant microprocessor function, or even redundant power supplies or inputs and outputs in critical applications. However, these features offer little incremental reliability, and greatly increase system first cost. Some designers consider manual system backup provisions to be more effective and more reliable than more complex systems that attempt to provide automatic system backup functions.

NOTE: ***Owing to the various needs of the application, a system designer should carefully consider the functions of the master control and selection of the hardware to provide these functions. This will help in improving the cost effectiveness of the facility and improve reliability.***

Another alternative to PLC-based master controls is the use of dedicated purpose microprocessor-based controls. These controllers are designed to provide core system functions with a preprogrammed circuit board. These may include functions such as load adding and shedding, load demand, master synchronizing, and power transfer functions.

3.12 Manual Operation Provisions

Even though modern on-site power systems are typically designed to be fully automatic and require no operator for proper system sequencing, there is still a need for manual controls to back up the automated portions of the system. The manual backup systems are useful during commissioning and service of the system to allow a technician to properly set up and adjust the equipment, and make diagnosis easier. They also can give a properly trained operator the ability to keep the system operating if there are certain types of system failures.

“Manual” controls are not completely manual in that they do have some automated characteristics that function to prevent operator errors from impacting on system reliability. For example, and manual synchronizing function will almost always incorporate a sync check function to prevent operator-initiated out of phase paralleling. So, some might consider these “manual” systems to be “semi-automatic”.

Certain system functions, such as voltage regulation, governing, and load sharing are inappropriate for manual control because of the speed and precision needed in the normal operation of these systems. An operator could not maintain a safe, usable power quality level by manually adjusting the fuel and excitation level on the generator set to provide these functions. Some other systems such as synchronization (generator set to bus or generator set to utility/mains) can be performed manually but generally are not fully manual (operation is via a sync check relay), because of the danger to the equipment due to operator error.

A key issue in deciding the level of manual control capability to provide in a system is the availability and skill level of operators—the ability of operators to make good decisions at critical times. Manual systems often back up control functions that are difficult to make redundant, such as power transfer operation.

Typical functions that can be provided include:

- manual starting and stopping of the generator sets in the system
- manual adjustment of the nominal frequency and voltage
- transfer of power from source to source

In the event that any of these functions are performed at the wrong time or in the wrong way, hazards to personal safety, power quality and equipment performance can occur. Detailed step by step instructions for any manual operation should be provided in a permanent location close to the equipment so that an operator can refer to them when they are needed.

3.13 Other Paralleling Control Systems

Paralleling equipment described in this section is not often used in modern applications due to the advent of low cost microprocessor-based control systems. However, they are described here in the interest of showing control systems that have historically been used, or to show some paralleling functionality that may not be revealed by more current system designs.

Paralleling control systems must always have synchronizing means, load sharing means, and generator protection. They often have operator control panels with AC metering, and many other functions. However, over the years, they have changed somewhat. The following materials describe paralleling control systems that have been used in the past, but now are not commonly used due to advancements in control technology that make more complex systems more reliable and cost effective.

3.13.1 Manual (Only) Paralleling

Manual paralleling (operator-initiated) systems provide a cost-effective method for paralleling of generator sets when an operator is available to start the generator sets and bring them on line. They are often considered to be the most reliable control arrangement, simply because they offer a very simple design. They are often a fall-back mode in more complex systems. Other common applications include portable rental fleet equipment and attended prime power installations.

Manual paralleling systems are generally composed of a paralleling breaker, synchronizing lamps (and/or a synchroscope), and nearly always a sync-check relay. In many cases the generator sets will incorporate droop governing and voltage regulation systems to control real and reactive load sharing in the system because these systems require no additional components on the generator set and no interconnecting wiring, but isochronous load sharing can also be used.

The operator will start one generator set, and close its paralleling breaker. The next generator set is then started, and the synchronizing lamps are turned on. Normally the lamps are connected so that when the lamp goes dark, the oncoming generator and the bus are synchronized. The voltage and frequency of the oncoming generator set may be adjusted to match the bus frequency and voltage, or to force the oncoming generator set to synchronize more quickly. When the oncoming generator set is synchronized the operator will manually close the paralleling breaker. A sync check relay is used to verify that the equipment is synchronized prior to breaker closing.

The operator can then make any necessary load sharing adjustments using the voltage and frequency-adjust potentiometers. Adjustments of the frequency and voltage during the manual paralleling process will affect the load sharing set up after the breaker is closed. Adjustments are necessary to bring the operating generator sets back into proportional load sharing state after the paralleling breaker is closed. This can be difficult to accomplish, especially for kVAR load sharing, as adjustment requires a stable inductive load and power factor or kVAR metering on each machine, in addition to the generator set ammeters.

The system is shut down by removing system loads, manually opening the paralleling breakers, and then allowing the generator sets to cool down at no load. The operator will then shut down the generator sets until the next need to operate the system.

In general, even though it is physically possible to manual parallel to a utility source, this practice is not recommended and is generally not allowed by utility authorities. The problem with manual paralleling of the utility service with a generator set is not the paralleling itself, but rather than the duration of time that the machine is paralleled is not controlled. Most utilities do not allow this practice for that reason. Some authorities are also uncomfortable with the risks associated with paralleling the utility to a partially disabled system, thinking that it might put other customers at greater risk.

3.13.2 Exciter Paralleling

Exciter paralleling is the most basic and traditionally the least expensive of the automatic paralleling systems. An exciter paralleling system requires no operator intervention to start and parallel the generator sets.

An exciter paralleling switchboard includes provisions for manual paralleling, such as: sync lamps, frequency and voltage adjustments, and a sync check relay with an electrically operated circuit breaker.

Exciter paralleling systems have often been used when it is desired for the system to be on line quickly, and the cost of the equipment is important. When both generator sets start quickly, the system will pick up all loads quickly, but if one unit doesn't start, the system must wait for the slower starting unit to either start or completely fail before the system can respond. Consequently, the system is usually not often used for critical or life safety applications.

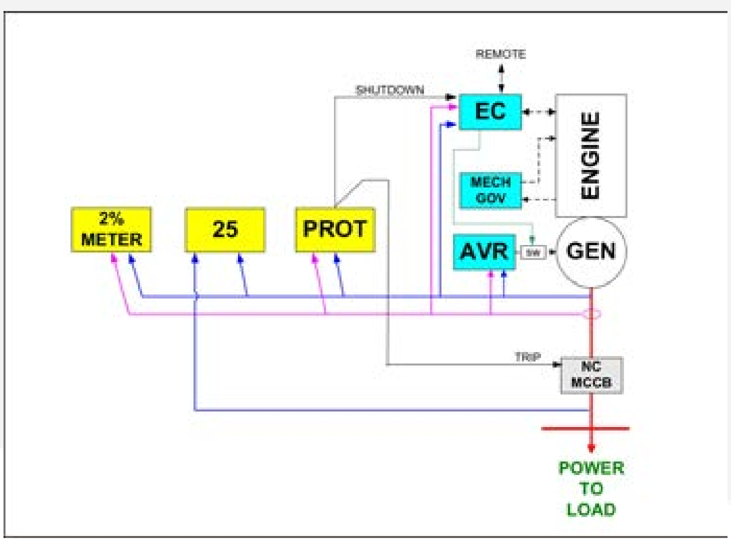


FIGURE 22. EXCITER PARALLELING CONTROL SYSTEM WHEN USING A NORMALLY CLOSED BREAKER WITH MANUAL PARALLEL BACK-UP.

3.13.2.1 Typical Sequence of Operation

In an exciter paralleling system, with the system ready to operate in an emergency mode the paralleling breakers are normally closed and the exciter field breakers are open. (Consequently, when the generator sets are started, they accelerated to rated speed, but produce no voltage until the exciter is enabled.)

On a signal to start, the system completes a time delay start period and the generator set engines crank, fire, and accelerate to rated speed. When the generator sets all reach start disconnect speed, the excitation system of all the generator sets are simultaneously switched on. Voltage then ramps up and synchronization automatically is achieved as each machine reaches rated voltage. Load sharing controls are then automatically engaged, whether in droop or isochronous operation.

When the start signal is removed, the system completes a time delay stop period, and the excitation systems are simultaneously switched off and the engines shut down.

If a generator set fails to start, the fail to start (over crank) protection on the generator set control operates, shutting down the generator set, tripping the paralleling breaker and initiating a load shed signal. All generator sets that have reached start disconnect speed then are allowed to continue in their automatic sequence.

When a generator set that has failed is once again ready to operate, the generator set is manually started, and accelerates to rated speed and voltage. The generator set is manually paralleled to the system bus using equipment as described in the manual paralleling portion of this chapter, and the paralleling breaker is manually closed. The operator then must adjust the load sharing controls to achieve proper load sharing in the system.

3.13.3 Sequential Paralleling

Sequential paralleling is an automatic paralleling method that connects generator sets to the bus in a predetermined order. To reduce control system cost, only one synchronizer is used. The synchronizer is switched from generator set to generator set in the established sequence. (A one line drawing of a sequential paralleling system is essentially the same as for an exciter paralleling system **Figure 22 on page 52**).

The system is not commonly used because of the delays in serving loads that can arise from following a predetermined order in the closing of generator sets to the bus, and in the risk associated with a single synchronizer operating all the machines (i.e., single point of failure issues).

3.13.3.1 Typical Sequence of Operation

Loss of normal power: The system start signal is generated by automatic transfer switches or other remote devices. On receipt of this signal, all generator sets automatically and independently start, accelerate to rated frequency and build up to rated voltage. When the set designated number one reaches a predetermined level of rated voltage and frequency, it is connected to the dead bus. Upon completion of their transfer time delays, the first priority transfer switches transfer their loads to the system bus.

The synchronizer is then connected between generator set two and the live bus. When the set designated number two reaches a predetermined level of rated voltage and frequency, it is synchronized and connected to the bus. Upon completion of their transfer time delays, the second priority transfer switches transfer their loads to the system bus.

The synchronizer is then connected between generator set three and the live bus. When the set designated number three reaches a predetermined level of rated voltage and frequency, it is synchronized and connected to the bus. Upon completion of their transfer time delays, the third priority transfer switches transfer their loads to the system bus.

Normal Power Restoration: After normal power has been restored and after the time delay on retransfer has expired, the transfer switches return to normal power and remove the system start signals from the control. The generator breakers are opened, and the generator sets are shut down.

Failure of a generator set to start or synchronize: If any generator set fails to start or synchronize, the controls will time out and connect the synchronizer to the next generator set in sequence.

4 Power Carrying and Distribution Equipment

4.1 Overview

FIGURE 23. EXAMPLES OF SWITCHBOARD/SWITCHGEAR EQUIPMENT IN NORTH AMERICAN, SOUTH AMERICAN, AND IEC-BASED DESIGNS.

Paralleling equipment is composed of generator control and protection equipment, master controls, power transfer controls and power sections. A “power section” is the equipment that transports power from the generator sources and routes it to the facility distribution system. In various countries around the world this equipment may be termed switchboard, switchgear, or panelboard. The power section of a paralleling system is very similar to the equipment used in a facility’s normal power distribution system. Traditionally, controls, monitoring, and protection for the generators, system level controls, and other devices have been built into paralleling power sections. In digital paralleling control applications, the paralleling controls and protection can be generator set mounted. Protective relaying and master controls may be built into the power section or may be supplied in separate enclosures.

This section covers power carrying equipment that is used in paralleling applications world-wide. This includes descriptions of necessary paralleling breakers, switchboard and switchgear design features, and variations that may be seen based on local rules. The term “switchboard/switchgear” is used in this document to generically describe the power section equipment provided in a paralleling application.

It is worth noting that this document contains many references and practical comparisons between North American and IEC practice. Equipment built under either standard practice is suitable for paralleling applications, and most appropriate based on the physical location around the globe where it is installed. It will be useful for designers working in a global environment to review these comparisons and hopefully develop a better understanding of each practice.

4.2 Requirements and Recommendations

4.2.1 Requirements

- Switchboards/Switchgear must be applied within their ratings, including applicable derating factors for altitude and temperature, and in compliance to country and local requirements and the limitations of the equipment design.
- Paralleling systems that use active synchronizing equipment must use paralleling devices that consistently and reliably operate within 5 electrical cycles, and have durability appropriate for the application. (For example, at least 3000 cycles under load.)

4.2.2 Recommendations

- Equipment features specified should be based on an evaluation of site conditions (including ambient temperature extremes, humidity, any corrosive conditions that exist, and elevation), equipment use, whether it is normally energized or de-energized, and a service and repair strategy.
- Power section equipment should be prototype/type-tested to assure that it will operate safely under both normal and abnormal operating conditions. In some locations (notably North America), 3rd party listing or certification is required to demonstrate compliance to various UL and IEEE standards. Similarly, some countries outside of North America require 3rd party review and certification to demonstrate compliance to relevant required standards.

4.3 General Considerations

Paralleling switchboards/switchgear are built in many configurations and a broad range of capabilities, especially considering the global market for this equipment. The designs of this equipment are driven by the following major factors:

- Rated operating voltage
- The level of fault current available from all sources connected to the bus structure.
- The steady state current levels throughout the switchboard/switchgear assembly, expected ambient temperature and allowable temperature rise of the equipment.
- The number and size of conductors to be connected to each installed device (and system bus, in some applications) based on the design loads,
- Access space and bending space required for installation and maintenance of connections,
- The required level of isolation of installed components, system bus structure, and source and load connections,
- Local and regional codes and standards

Switchboard/switchgear designs are also impacted by local environmental conditions such as extreme ambient temperature, dust/moisture, seismic conditions, or the presence of corrosive elements in the atmosphere. In some cases the designs are also impacted by the level of protection required for personnel who work on or around the equipment, and the reliability requirements of the facility power system.

4.3.1 Location in the Distribution System

It is important to note that the Paralleling Switchgear Package is an integral part of the larger power distribution system on any given site that it is installed into and usually has interfaces to one or more of the following equipment:

- Generator sets
- Automatic Transfer Switch or Switches
- Main Switchboards or other Distribution Switchboards
- UPS
- Other electrical equipment, including downstream distribution equipment to loads.

It is therefore necessary to have a complete understanding of the larger power distribution system prior to operating any equipment.

4.3.2 Prototype Testing/Type Testing

On the surface, switchboards/switchgear look simple to design, but the design process can be quite complex in order to meet all the performance and installation requirements of an application.

FIGURE 24. PROTOTYPE TESTING REQUIRES EXPENSIVE AND TIME CONSUMING WORK, BUT RESULTS IN A SAFER AND MORE RELIABLE DESIGN.

While there are guidelines that can be used to describe the performance of a switchboard/switchgear line-up such as steady state current ratings throughout the equipment, short circuit bracing, and safe spacing between the energized components, the equipment can be required to transport a large amount of energy and thus performance, particularly under short circuit and other fault conditions, is not completely predictable.

Consequently, prototype testing (also termed “type testing” in IEC markets) is necessary to validate the design of switchboards/switchgear in any critical application. Prototype testing is generally required by authorities in North America and is common practice in many countries. Third party certification or listing of the equipment greatly reduces the risk of inappropriate design, and leaves the designer in a position of simply validating the level of current flow under steady state and transient conditions, and taking appropriate derating actions when ambient conditions exceed the manufacturer’s base equipment design points. More information on derating practices can be found Section 4.5.5 on page 75.

Prototype/type tests for switchboards/switchgear include:

- Temperature rise limits
- Dielectric properties
- Short-circuit withstand
- Effectiveness of the protective circuit
- Clearances and creepage distances
- Mechanical protection
- Degree of protection

Manufacturers will also perform the following tests on both prototype and production equipment:

- Wiring, electrical inspection
- Insulation – dielectric tests
- Protective measures

By completing this testing, especially when witnessed by an independent laboratory, designers have a higher degree of confidence in the reliability and safety of the equipment to both the facility in which they are installed, and to the facility operators.

The practices to achieve the general design goals in switchboard/switchgear equipment are complex, and certification/listing practices are also complex and beyond the scope of this document to explain.

The only negative to the requirements for prototype testing/certification and type-testing is the additional cost associated with providing the expertise necessary and performing the work, including supplying prototype equipment, manpower and facilities for testing, and in some cases costs associated with third party certification of the designs. Of course, there are also costs in terms of lead time when customized designs are used that have not been previously tested and considerably greater risk of failure of the equipment, especially under extreme conditions.

4.4 Power Section Equipment

Power section equipment is available in many styles, construction practices, and ratings. Terminology for these devices varies in different geographic regions, but functions and features are similar. Commonly used functions and terminology are shown in the table below.

TABLE 3. COMMONLY USED TERMINOLOGY FOR SWITCHBOARD/SWITCHGEAR EQUIPMENT

North America	IEC	Function
Main Devices (utility/mains source)	Main	Provides power to a primary distribution system; may be from a utility/mains source, or from a generator (non-paralleling) or multiple generator bus.
	Incomer	Incoming supply from a mains supply, generator supply, or a sub-main supply.
Feeder Devices	Sub-main	Distributes power from a main device to one or more “lower” level circuits.
Branch Circuits	Sub-circuits	Provides power to serve loads.
	Functional Unit	Circuit breakers, fuses/switches, contactors, switches, protective relays.
Motor Control Centers	Motor Control Centers	A specialty switchboard that provides protection and control for directly connected motors.
Circuit breaker: air circuit breaker, power circuit breaker, insulated case circuit breaker, molded case circuit breaker	Switchgear (general term), ACB, molded case circuit breaker	Devices used for protection of the installed equipment as well as downstream equipment and devices. An appropriately selected circuit breaker will usually be used as a device to connect or disconnect a generator set to a paralleling bus.
Tie Breaker	Bus Coupler	Connects two bus structures together, generally for the purpose of allowing multiple sources to feed each bus.
Bus Risers	Vertical Bus	Connects devices together with a common vertical bus and (usually) to a common horizontal bus.
Main (cross) Bus	Busbar or Busbars	The common horizontal structure connecting several sections of equipment together.
Bus Duct	Bus Duct	A bus structure that connects individual switchboards/switchgear with one another.

Equipment is generally built to locally accepted standards, which include the following standards:

- IEC61439 low voltage equipment; Asian markets in general are open to both Non-Type Tested and IEC 60439-1 Type Tested switchgear.
- Australia and New Zealand equipment must comply with AS/NZS 3439.1, which is an extension of IEC 60439.
- IEC 60439-1994 Low voltage switchgear and control assemblies.
- IEC 61439-2009 Low voltage switchgear and control assemblies.
- BS EN 60439-1994 Low voltage switchgear and control assemblies.
- BS EN 61439-2009 Low voltage switchgear and control assemblies.
- CCC Certification in (Peoples Republic of China).
- UL 67 Panelboards.
- UL 891 low voltage switchboards.
- UL 1558 low voltage switchgear (generally validates a design for compliance to IEEE C37.20.1).
- ANSI/IEEE C37.20.1, Metal Enclosed Low Voltage Power Circuit Breaker Switchgear.
- ANSI/IEEE C37.0.2, Metal Clad Switchgear (medium voltage).

- UL 1670 medium voltage switchgear (generally validates a design for compliance to IEEE C37.20.2).

See **Section 8.6 on page 259** for general information on these standards. In general, compliance to N American standards (UL, CSA, ANSI/IEEE standards) is required in North American applications. These standards are also applied on some projects in Puerto Rico, the Philippines, Korea, Taiwan, and occasionally in Mideastern countries. IEC standards are very commonly used in Europe and most other parts of the world where standards are used. IEC standards are also the basis for Australia and New Zealand standards. CCC standards are most similar to IEC standards, but there are notable differences. Always refer to the specific standard in force for detailed information on requirements.

Switchboard/switchgear equipment enclosures are generally constructed of mild steel, but may also be provided in stainless steel or polymer-based designs, especially for situations where the equipment is installed in harsh environments, such as a chemical plant or refinery. The enclosures may be designed for indoor (less-protected) environments, or outdoor environments.

Switchboard/switchgear equipment is generally rated based on its ability to continuously carry electrical current within a specified temperature rise and the magnitude of fault current that the equipment can safely withstand.

A key differentiating feature in switchboard/switchgear is the level of isolation there is between the various components installed in the equipment. Since electrical circuits can carry very large amounts of electrical energy, failure of a circuit or component in the system can result in major damage not only to the failed component, but also to the surrounding equipment. Isolation means of various types allows a switchboard/switchgear system to more reliably survive different types of fault conditions. With more isolation better protection is achieved, but at significant increases in cost. Isolation also contributes to personnel safety, and helps to prevent accidents. More information on this topic is provided **Section 4.4.1.4 on page 65**.

The power-carrying equipment installed within a switchboard/switchgear lineup is typically connected together with rectangular solid copper bars, extruded copper, or aluminum bars. Some designs take advantage of flexible copper bars or cable interconnections, but use of these materials can have an impact on the ability of the overall design to meet required short circuit ratings.

In addition to various types of protective devices, many types of associated equipment can be provided, including meters, current transformers, manual switching devices, protective devices, control devices, wiring, terminal blocks, etc. These devices are commonly selected based on the functional needs of the application, as well as considerations for necessary testing, and safety for maintenance and upgrades.

In North America, there are three general levels of switchboards/switchgear that are commonly provided for low voltage applications:

- Switchgear: which is generally applied at the “top” of a distribution system (near the service entrance), and is used primarily in larger facilities. This equipment usually requires freestanding enclosures connected by a common bus and requires both front and rear accessibility. Devices are individually mounted and draw-out in design.
- Switchboards: which are commonly used at the “top” or “middle” of a distribution system, and is used in smaller/mid-size facilities. The equipment enclosures are commonly connected together with a common bus and is designed to be accessible from front and rear, or front only. Devices may be individually mounted or group mounted.

- Group Mounted (Panelboards): which are used primarily for distribution of power to load circuits (the “bottom” of a distribution circuit). This equipment is usually placed against a wall and is designed for front access only.

In other parts of the world, there is no commonly used distinction between equipment used in various parts of a facility distribution system. All the different variations are termed “switchboards”.

See tables below for general uses and application of this equipment.

TABLE 4. CHARACTERISTICS AND TYPICAL USES OF SWITCHBOARDS/SWITCHGEAR (NORTH AMERICA)

	Low Voltage Switchgear	Rear-Connected Switchboards	Group-Mounted Switchboards
Fault Current Handling	High Currents, service maintained downstream Selectively coordinated	High Currents, time delayed instantaneous trips available Selective coordination	Lower Current Levels Instantaneous Trips Not selectively coordinated at less than 0.1 seconds
Application	Heavy Industrial/Primary Distribution	Large Systems/Primary Distribution	Smaller Systems/Primary distribution; Feeder/Branch circuit distribution
Environment	Poor environments/heavy switching duty	Cleaner environments/some switching	Clean environments/nearly no switching
Maintenance	Maintainable arc chutes, contacts, springs, and other accessories on breakers	Little or no internal maintenance on breakers	No maintainable or repairable internal parts.
Typical Applications	Petrochemical Water Treatment Pulp and Paper Steel	Large Hospital Data Centers Large Retail Commercial	Small Healthcare Small Retail Small Commercial

TABLE 5. SWITCHBOARD/SWITCHGEAR CAPABILITIES

	Low Voltage Switchgear	Rear-Connected Switchboards	Group-Mounted Switchboards
UL Listing Standard	UL 1558	UL 891	UL 891
UL Circuit Breaker Standard	UL 1066	UL 489	UL 489
IEC Standard	IEC 61439	IEC 61439	IEC 61439
Bus Joints	Bolted joints to meet temperature rise requirements	Bolted joints to meet temperature rise requirements or cross-sectional area requirements	Bolted joints to meet temperature rise requirements or cross-sectional area requirements
Field Connections	Stationary load bus and lugs in rear compartment	Stationary load bus and lugs in rear compartment	Direct connection to devices
Drawout Devices	4-position drawout required: connected, drawout/test, isolated, withdrawn	Drawout optional	Not available
Doors/Covers	No exposed components	Front of CB case allowed to be exposed	Front of CB typically exposed

4.4.1 Switchboard/Switchgear Construction/Description

4.4.1.1 General Construction: Bus Structure, Bracing, Barriers

There are many different common construction techniques for switchboards/switchgear used in paralleling applications, but they are nearly always constructed from formed and either bolted or welded steel, with access derived from doors or removable panels. Key differences in the equipment revolve around the segregation (barriers) between different components of the system. Barriers are used to isolate equipment and systems (such as bus structures) to prevent accidental contact with live components or to limit damage if there are internal faults in the switchboard/switchgear.

Switchboard framework can be constructed with formed and bolted design, or with a formed steel and welded design. Welded designs are sometimes considered to be more “heavy duty”, but bolted construction meets the same structural performance requirements, and offers greater manufacturability (lower cost) and greater ease of repair or expansion of the system.

Minimum material thicknesses for specific parts of a structure are often specified by codes and standards, with decisions commonly based on the strength of material necessary to withstand the mechanical stresses that occur during a short circuit condition, or to prevent migration of faults either outside of the structure, or to contain a fault within a specific section of the structure, or to prevent the distortion of lift-off panels and doors. Obviously, the thicker materials result in a more rigid structure that can do a better job of withstanding the stresses of fault conditions, seismic conditions, and transport, but will cost significantly more. Over-sizing provides no value if it does not result in better performance in a measurable way. While modeling tools are available to simulate the ability of a specific design to successfully withstand the required conditions, designs usually prototype tested (as noted previously in this section on page 57) to verify that they perform successfully. Some standards, such as UL 891, allow building to established guidelines to limit prototype test requirements in certain situations. These guidelines are generally very conservative, and result in a more costly structure from the perspective of material cost, but allow for greater flexibility in equipment supply to meet application requirements.

As most switchboard/switchgear equipment is constructed of mild steel, it must be protected from corrosion, typically by applying a paint coat over the steel structure. It is critical that all surfaces of the steel be coated, and that the steel is properly cleaned and appropriate paints are used for the base and final coatings. There are major restrictions on the use of volatile liquids in paints in many countries, and these restrictions often have a negative impact on final paint quality. Consequently, many equipment suppliers have moved to the use of powder painting processes that are baked to finish the paint. The result is a flexible, durable surface that is suitable for most environments.

Equipment that is applied out of doors, in coastal environments, or in corrosive environments requires special attention to achieve acceptable useful life of the equipment. (See Environmental Protection in the following section for more information.)

Access doors or bolt-on panels can be used to allow access for installation, regular maintenance or service. In general, panels that have mounted components or panels that must be opened for regular inspection or service should be provided with hinged doors. Locking provisions or bolt-on panels should be provided when the equipment is accessible to un-trained personnel. Bolt-on panels are suitable for situations where the structure or contained equipment does not require regular service, or when it is desirable to limit access for safety reasons. Where access doors or panels are provided by a manufacturer access must be maintained for maintenance of the equipment. Equipment should not be energized with these panels open, except when necessary for service. Under that situation, protective equipment may be required for personnel in the area of the equipment.

Outside of the North American continent cable access into switchboards/switchgear is usually not via conduit but via single or multiple cable per phase connections, commonly run in cable trays. This necessitates the requirement for non-ferrous gland plates to be installed at the switchboards/switchgear cable entry point. These are typically manufactured from brass or aluminum material. Non-ferrous materials are required to stop eddy currents flowing between the cables, creating a magnetic field which in turn creates heat which can be damaging to equipment and wiring materials.

4.4.1.2 Environmental Protection

Switchboard/switchgear failure can occur due to accumulation of dust and dirt or other contaminants in the equipment, particularly in the presence of moisture. For this reason, switchboards/switchgear are designed and rated for use in specific types of applications based on their resistance to ingress of dust, dirt, and moisture.

4.4.1.3 NEMA/IP Enclosure Types

Enclosures for electrical equipment should be specified to include environmental protection that is appropriate for a specific application.

North American practice and terminology is different than that used in IEC applications.

In North America, equipment environmental protection is described in National Electrical Manufacturer's Association (NEMA) standards. NEMA has defined a series of standards that will provide a wide range of protection depending on the needs of the application. Commonly used standards include:

- NEMA 1 enclosures are designed for use in indoor environments, and provide a basic level of protection against accidental and intentional contact with energized components in situations where no special environmental conditions exist.
- NEMA 12 enclosures are designed for use in indoor environments, and provide protection against dust, dirt, and dripping water.
- NEMA 3R are designed for use in outdoor use, primarily for protection against falling rain. They also are not damaged by ice formation on the enclosure.
- NEMA 4 enclosures are designed for use in indoor or outdoor environments, and protect internal equipment from rain, dust, sprayed water, and ice formation.
- NEMA 4X enclosures provide the same features as NEMA 4, and also provide enhanced corrosion protection.
- NEMA 12 enclosures are designed for indoor environments, and provide protection against dust, dirt, and dripping or minor splashing of water.

Enclosures used outside of North America typically use IEC standards to describe the environmental performance requirements of the equipment. The capabilities of the equipment are described using an ingress protection (IP) designation with a numeric code, in which the first number indicates the level of protection against dust/dirt and accidental contact, and the second digit describing the level of protection against liquids entering the enclosure. The general ratings are described in the table below.

TABLE 6. IEC ENCLOSURE INGRESS PROTECTION DEFINITIONS

	Solid Entry and "Touch" Protection (1st number)	**Water Entry (2nd number)**
0	No protection	No protection
1	Protected against accidental contact but not intentional contact. Solids greater than 50mm	Protected against drops of condensed water
2	Protection against intentional or accidental contact by finger. Any solid object up to 12 mm	Protected against vertical drops of liquid. as demonstrated by protection against direct sprays of water up to 15 degrees from the vertical
3	Protection against contact by tools and wire; Any solid object up to 12mm	Protection against rain, as demonstrated by direct sprays of water up to 60 degrees from the vertical
4	Protection against contact by small tools and wire; any solid object greater than 1mm	Protection against water sprayed from any direction – limited ingress permitted
5	Complete protection against contact by any tool, wire or other object; protect against damaging levels of dust	Protection against water from low pressure jets from any direction (some ingress is permitted)
6	Totally protected against dust	Protection against ingress of water when submerged
7		Protection against ingress of water when submerged at a defined pressure and time duration

Very specific and detailed prototype/type test procedures are followed to verify the capability of specific enclosure designs to meet NEMA or IEC IP performance requirements. Consequently, the descriptions of capability in this section are characterizations of the capability of different cabinet designs. Actual performance is defined by specific tests. However, general comparisons can be made between the NEMA and IEC ratings for enclosures. Results are shown in the table below.

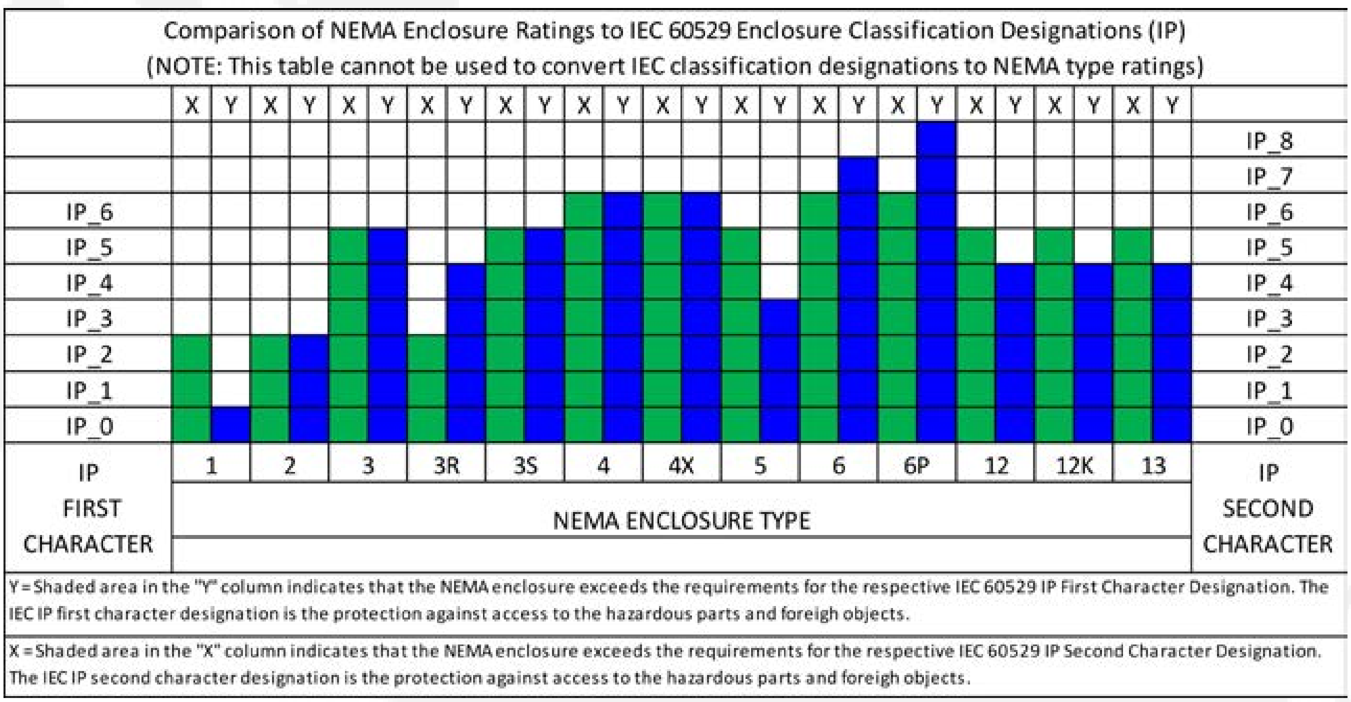


FIGURE 25. COMPARISON OF IEC VERSUS NEMA ENCLOSURE RATINGS

In addition to selection of an appropriate enclosure for an application, some applications will require use of anti-condensation heaters for outdoor equipment, humid environment, or coastal environment, especially if the equipment is normally not energized. Paralleling equipment and associated distribution equipment is often de-energized for long periods of time and is commonly specified with anti-condensation heaters as a result.

4.4.1.4 Isolation and Barrier Types

As noted previously, switchboard/switchgear designs may require different types of barriers based on the designer's determination of the need for personnel safety, equipment safety and reliability under maintenance and fault conditions. The table below displays IEC construction terminology and compares it with NEMA terminology.

TABLE 7. COMPARISON BETWEEN NORTH AMERICA AND IEC CONSTRUCTION TERMINOLOGY

IEC Terminology	North American	Description
Form 1	Group-Mounted, Panelboard	Devices are commonly mounted in an enclosure, with no physical separation between equipment.
Form 2		Separation of bus bars from functional units
Form 2a		Terminals for external conductors NOT separated from the bus bars.
Form 2b		Terminals for external conductors separated from the bus bars.
Form 3	Individually mounted	Separation between bus bars and functional units. Separation between functional units. Separation between terminals for external conductors and the functional units.
Form 3a	Individually mounted, isolated	No separation between terminals for external conductors and bus bars.
Form 3ah		As for Form 3a except separation between functional units is achieved by the use of the functional units own integral IP2X rated integral housing
Form 3b		Separation between terminals for external conductors and bus bars.
Form 3ah		As for Form 3b except separation between functional units is achieved by the use of the functional units own integral IP2X rated integral housing. Terminals separated from bus bars by standard construction.
Form 3bi		As for Form 3b except separation between bus bars and functional units and terminals for external conductors is achieved by the insulation of the bus bars.
Form 3bih		Separation between bus bars and both functional units and terminals for external conductors is achieved by insulation of bus bars. Separation between functional units and between functional units and their terminals for external conductors is achieved by the use of the functional units own IP2X rated integral housing.
Form 4		Separation bus bars from the functional units and terminals. Separation of functional units from one another. Separation of terminals associated with a functional unit from those of another functional unit.
Form 4a		Terminals in the same compartment as associated functional unit.
Form 4b		Terminals NOT in the same compartment as associated functional unit.
Form 4ah		As for Form 4a except separation between adjacent functional units is achieved through the use of the functional units own integral IP2X rated housing.

IEC Terminology	North American	Description
Form 4bh		As for Form 4b except separation between adjacent functional units is achieved through the use of the functional units own integral IP2X rated housing.
Form 4bi		As for Form 4b except separation between bus bars and functional units is achieved by the insulation of the bus bars.
Form 4aih		Separation between bus bars and functional units and terminals for external conductors is achieved by insulation of bus bars. Separation functional units is achieved by the use of the functional units own integral IP2X rated housing.
Form 4bih		Separation between bus bars and functional units and terminals for external conductors is achieved by insulation of bus bars. Separation between terminals for external conductors of functional units is achieved by standard construction.

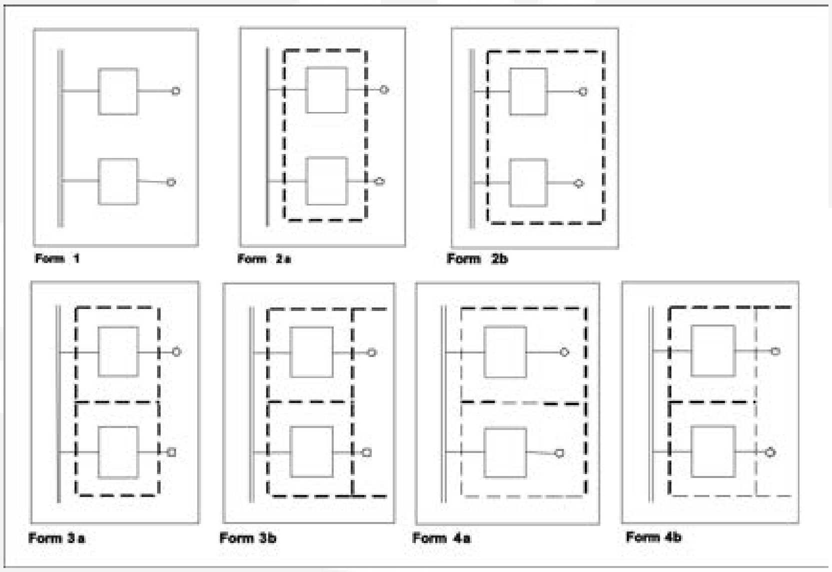


FIGURE 26. IEC SIMPLIFIED ILLUSTRATIONS OF FORM FACTORS ILLUSTRATING LEVEL OF ISOLATION PROVIDED FOR EQUIPMENT IN A SWITCHBOARD/SWITCHGEAR STRUCTURE.

While barriers provide value by minimizing the impact of fault conditions and personnel safety by minimizing exposure to live components, they also add greatly to equipment cost and maintenance complexity. Another means of achieving better equipment reliability is the use of insulation on the bus structures, both to present accidental contact, and to prevent arcing/tracking when bare bars are too close together. Insulation also helps to prevent arcing and propagation of arcing faults.

In North America a metal clad construction built to ANSI/IEEE C37.20.2 is typically used for medium voltage switchgear. ANSI/IEEE C37.20.2 defines metal clad switchgear as having the following characteristics (among others)

- Drawout breakers
- Breakers, buses and transformers completely enclosed by grounded metal barriers, including a metal barrier in front of or part of the breakers so that no primary circuit components are exposed by opening a door.
- All live parts are enclosed within grounded metal components
- Bus bars are fully insulated.

- Automatic shutters that cover primary circuit components when the removable element (drawout breaker) is in the disconnected, test or removed position.

Under the IEC Standards Separation barriers may be provided by several means:

- PVC sleeving, wrapping or plastic coating of conductors
- Insulated terminal shields or PVC ‘boots’.
- Rigid insulated barriers or partitions.
- Compartments formed from grounded metal.
- A device’s integral housing.

Note that in North America practice bus insulation is not required in low voltage switchboards/switchgear, but may be added. Most arc-flash resistant switchgear designs utilize this practice.

Bus differential relaying can also be used when a higher level of equipment protection is desired.

4.4.1.5 Wiring Access Considerations

Applicable codes and standards include requirements for minimum wiring space for connection of conductors to the switchboard/switchgear devices and bus structure. There are significant differences in requirements depending on local requirements, so care must be taken to properly select the number, size, and type of conductors used, and verifying that the switchboard/switchgear will have sufficient access space for the wiring. (Access to all fasteners in the system is required for regular equipment maintenance.)

Control wiring will include but not be limited to the wiring going to CTs, protection relays, circuit breakers and auxiliary equipment. Many codes and standards, as well as equipment manufacturer requirements require that DC control wiring is separated from AC control wiring. The use of PVC cable trays/ducting or PVC conduit within a switchboard/switchgear assembly are the most common ways to manage wiring for ease in manufacture and tracing of wiring problems for service. Attention should be given to spare space within ducts and conduits both internal to the switchgear and externally for future expansion or replacement of existing wiring within the assembly.

It is also important to plan for the ability to load test generator sets using temporary load banks. In general, enclosures on generator sets will only have space for a single set of fully rated conductors, so provisions elsewhere in the system for load bank testing can save significant time and cost over the life of the system.

One factor that is often missed in this work is that the use of compression type terminations versus mechanical lugs will change the space required for conductors. More bend space is needed for compression devices, but they are considered to be more reliable. See the figure below for an illustration of the difference in these terminals.

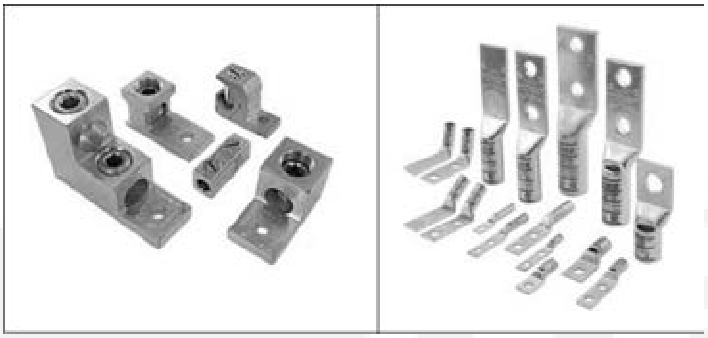


FIGURE 27. MECHANICAL LUGS (LEFT) VERSUS COMPRESSIONS LUGS (RIGHT).

4.4.1.6 Bus Ducts

A bus duct is a manufactured product that may be used to interconnect switchboard/switchgear equipment located in various parts of a facility. Rather than utilizing a cable/lug assembly, the bus ducts are commonly connected to the switchboard/switchgear equipment using bolted bus bar connections.

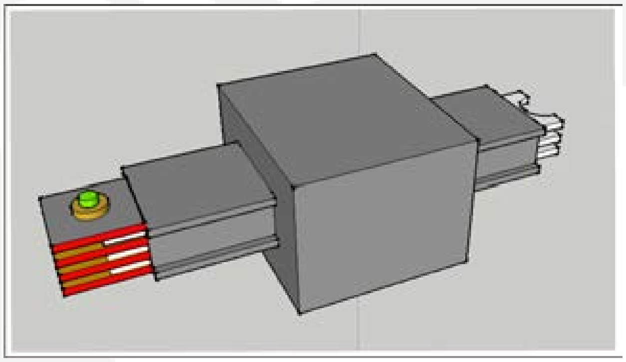


FIGURE 28. TYPICAL BUS DUCT SECTION WITH CENTER TAP FOR CABLE CONNECTIONS.

Bus duct is commonly specified when there are spacing limitations for conductors in a facility or that may also require large numbers of high current circuits. Bus ducts may also be utilized to maintain high fault levels within an electrical main distribution system. Numerous manufacturers of bus dusts within the global market place produce bus ducts rated with fault levels of 120 kA.

Bus duct equipment must be specifically designed for the facility where it is installed. Orientation of the switchboard/switchgear equipment and other factors can have an impact on available spacing for this equipment.

When connected to generator sets, bus ducts are installed to a point adjacent the alternator terminal box and then connected to the alternator by means of multiple flexible cables so as to ensure there is no rigid connection to the generator set. This is required due to vibration inherent in all generator set applications.

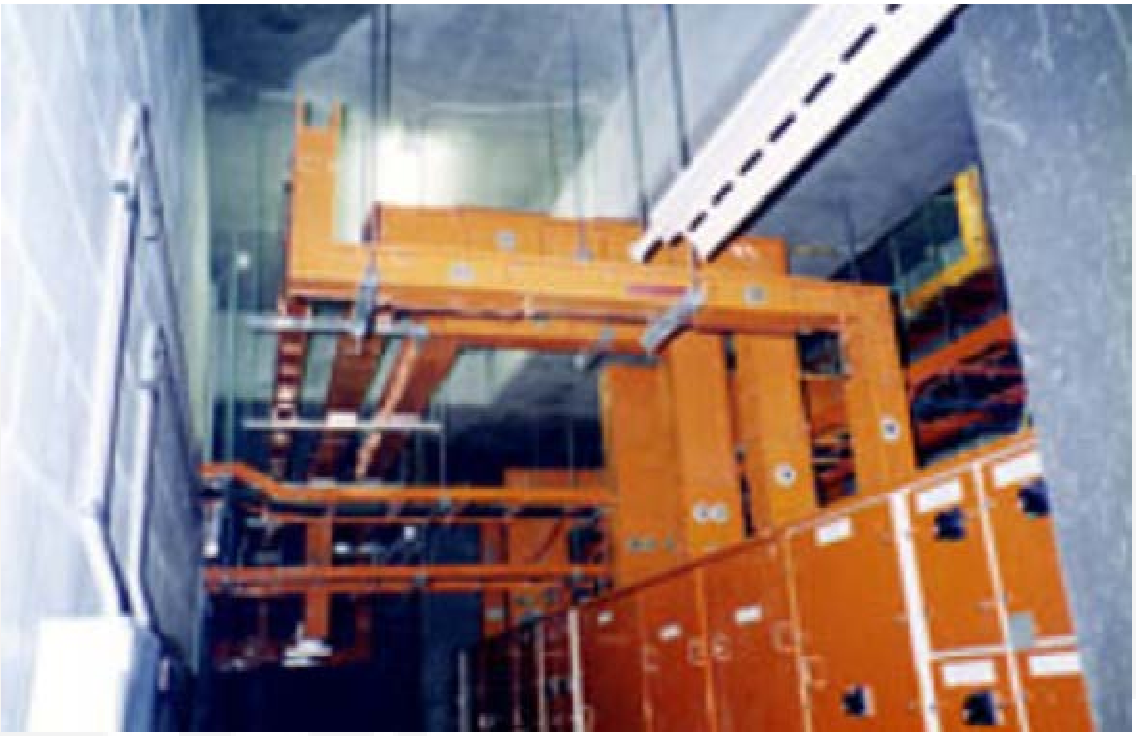


FIGURE 29. BUS DUCT INSTALLATION FROM IEC SWITCHBOARD

4.4.1.7 Service Entrance Considerations

The service entrance of a facility is the electrical location where the conductors from a utility/mains service enter a facility. In a facility where the utility/mains service is the only source of power, the service entrance commonly has special requirements relative to other switchboard/switchgear equipment. These include:

- The “bonding” or grounding/earthing point in the facility. In any facility electrical distribution system there can be a maximum of one point in the facility where the neutral conductors are connected to the facility electrical grounding/earthing system. Neutral conductors may be isolated by transformers or switching devices to allow proper system protection and safety. For example, 4-pole transfer switches allow bonding of a generator neutral to earth/ground at the generator set, while bonding the utility/mains service at the utility service entrance to the facility.
- Barriers for electrical safety to allow service of downstream equipment (including the service entrance equipment) by physically opening the circuit that connects the facility distribution system to the utility service.
- Appropriate labels to describe the equipment and function.
- Lock-out/Tag-out provisions, which allow a service technician to prevent inadvertent energizing of the electrical system while it is under service.

These provisions are usually required by local codes and standards.

4.4.1.8 Utility Metering Compartments

Without exception all Utility companies globally set down specific requirements for metering compartments. These requirements typically will apply only to the utility/mains service entrance. Equipment must be installed per the servicing utility requirements or it will not be energized by the service supplier.

4.4.1.9 Arc Flash Limitation Measures

While switchboards/switchgear are specifically designed and tested to verify their ability to safely carry short circuit and overload current, misoperation of the equipment, poor maintenance, or service errors can causing arcing faults that can seriously damage the equipment. These conditions are also extremely dangerous to personnel in the vicinity of the equipment, potentially even if the switchboard/switchgear equipment is operating with all doors closed and barriers in place. Consequently, increasingly stringent requirements are becoming common to validate the capability of equipment to mitigate the impact of arc fault conditions, particularly in North America.

If Arc Flash is of major concern then a way to minimize the potential for damage is to fully insulate all of the bus bars and joints within the switchboard and provide appropriate barriers. However, this does come at a relatively higher cost, including a potential to require increasing the size of the bus bars within the switchboard due to greater difficulty in the design rejecting heat. The most cost effective solution is to prohibit anyone working on a live switchboard, and the use of appropriate protective procedures, equipment, and clothing. It is also most practical to locate primary distribution equipment in areas that are not commonly accessible to untrained or ill-equipped workers.

4.4.1.9.1 Arc Fault Containment (Internal Arcing Faults)

For many years, IEC Low-voltage switchboard/switchgear and control gear assembly standards have contained guidelines for assemblies intended to provide increased security against the occurrence of the effects of Internal Arcing Faults. Similar requirements are now also in place in North America via 3rd party certification to the requirements of IEEE 472 for low voltage switchgear equipment. Generally, medium voltage equipment is provided with arc fault mitigation provisions as a standard practice.

The standards describe the problem of internal arcing which may occur in an assembly during service, and cover the design principals and requirements that should be considered to reduce the risk of its occurrence or to limit its effects. Qualification of the equipment commonly involves testing of a specific design to validate its capability, since the arc fault phenomena is not reliably predictable based on building to a design standard.

The guidelines have specific objectives and cover one or more of the following:

1. To provide means to reduce the probability of an internal arcing fault.
2. To protect personnel from injury in the event of a fault under the normal operating conditions of the assembly.
3. To limit as far as possible the extent of damage to equipment in the event of a fault

In general, North American installation codes and standards do not require use of switchboard/switchgear equipment that includes arc fault containment provisions or qualifications, so use of this equipment is a decision that is made between the system designer and the equipment owner. Designers should be aware of local requirements for arc fault protection of personnel in a facility, the impact of an arc fault event on system reliability and availability of critical power, and the incremental costs of the provisions so that the most appropriate equipment is specified and provided for a facility. It should also be recognized that equipment with arc fault containment provisions will be more expensive (due to added hardware, certification, and number of suppliers of the equipment); and may require somewhat longer lead times for design and production than more conventional equipment.

Many manufacturers now provide arc flash resistant switchgear as a standard product. This equipment is specifically tested to demonstrate compliance to IEEE 472 or IEC 60439. These tests verify that an arc flash event will not propagate through the switchboard/switchgear, will not allow arc flash energy to escape to locations around the switchboard/switchgear where personnel are likely to be working, and will not result in energizing any normally grounded component. An arc flash event will generally severely damage or destroy the breaker associated with the fault within a switchboard/switchgear section.

4.5 Ratings

Power sections are rated based on the steady state current that can by carried by the main bus at a specific ambient temperature and the short circuit current level that the structure is designed to withstand, called the bracing rating.

The main bus may be fully rated (that is, each section carries a bus structure with the same steady state current rating); or the bus may be reduced in steady state rating in sections where the current flow cannot possibly reach the bus rating based on the location and size of the sources in the bus structure, and the location and size of the load breakers. This arrangement is called a tapered bus design. The primary advantage of a fully rated bus is that it allows extensions to the system with less concern for overall bus rating. A tapered bus design usually uses less material, and will usually cost less than a fully rated design. All bus rating is based on continuous operation at the steady state rating level with a maximum temperature rise in the bus at any point in the system (temperature rise allowed varies with applicable standards that are applied) at a maximum ambient temperature (usually 40 °C). The temperature rise of a system depends on the materials used in the bus itself (grade of copper, or in some areas, aluminum used) which will have higher temperature rise for similar physical characteristics to copper.

4.5.1 Steady State Ratings

Like nearly any electrical device, current flowing through a circuit breaker or bus structure will generate heat due to the resistance to current flow in the current path. As current flow increases, heating increases; and as the ambient temperature around an electrical device increases, it becomes more difficult for the device to reject all the heat produced by current flow. If the heating impact is large enough, insulation can be damaged or the structure of the device may be damaged, causing a safety hazard, reduced life, or nuisance tripping of thermal activated devices. It is also possible that some protective devices, such as breaker trip units or protective relaying, may misoperate or be damaged by these high ambient temperatures.

The biggest factor in the temperature rise of the structure is the current density in the bus structure. In essence, using more material (copper or aluminum) or more electrically efficient material (copper) will keep temperature down making temperature rise lower, at the expense of higher equipment cost.

Some designs require inherent or forced ventilation to limit temperature rise in the structure to acceptable levels. (Note: there are restrictions in the use of forced ventilation in equipment designs that are IEC or UL Listed. IEC does not currently allow forced ventilation.) If equipment ratings are based on the presence of inherent or forced ventilation, and if that ventilation is not present, the equipment ratings are greatly reduced. Use of ventilation in the system design allows more foreign material such as dirt and moisture to reach internal components, which results in greater maintenance needs and to some degree, lower reliability if regular maintenance does not occur. When an equipment design includes filters to minimize ingress of dust and dirt, regular maintenance of filters is required, or again, temperature rise limits may be exceeded, particularly under high ambient conditions.

The main bus used in paralleling equipment may be arranged horizontally or vertically through the power section structure, unless the system design is small enough that all the components can fit into a single switchboard/switchgear section. The selection of the bus structure and design is impacted by considerations for temperature within the structure and bus itself, bracing restraints, and connection/maintenance provisions. In general, it is harder to meet temperature rise limits when the bus is in the upper part of the structure and harder to meet higher bracing requirements when horizontal structures are used.

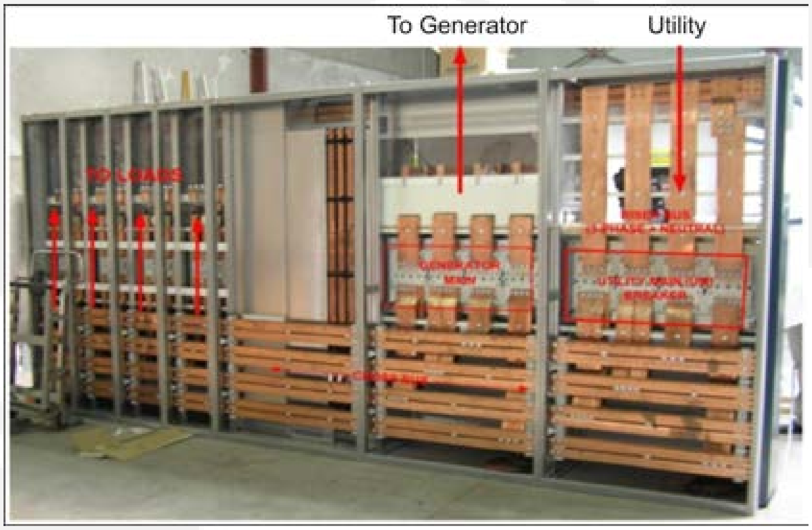


FIGURE 30. VERTICAL BUS STRUCTURE (CROSS BUS BARS ABOVE EACH OTHER) IN AN IEC SWITCHBOARD DESIGN

As a general rule in North America, switchgear designs are based on a maximum bus bar temperature rise of 65 °C in a 40 °C ambient which equates to a maximum ambient temperature of 105 °C when operating at rated current. Depending on the standard used for certification of a design, the temperature rise may be tested on the bus bar exposed to open air, so actual temperatures inside a switchgear structure may be significantly higher than the 40 °C ambient that is the basis for their design. Thus, when electrical equipment is operating at full load, it is not unusual for the surface temperature of the electrical enclosure to be uncomfortably hot. It is also reasonable to remember that many installations may subject equipment to operation in temperatures above 40 °C, and in those cases appropriate derating practices should be used.

Outside of North America as a general rule IEC standards are adopted. IEC switchboard designs are based on a maximum copper bus bar temperature rise of 75 °C in a 35 °C ambient, which also equates to a maximum ambient temperature of 105 °C when operating at rated current. IEC compliant switchboards are also limited by requiring that surface temperatures of accessible external enclosures and cover surfaces may not exceed specific temperature rise limits, i.e., metal surfaces: 30 °C and insulating surfaces -40 °C.

4.5.2 Switchboard/Switchgear Short Circuit Ratings

When a short circuit occurs downstream from a switchboard/switchgear line-up, the system must carry the fault current until protective devices isolate the fault. The bracing rating of a bus describes how much current can safely be carried by the equipment for the duration of a fault. This is sometimes termed the “short circuit” rating of the system. When current in a bus structure suddenly increases during a fault condition, the magnetic fields around the bus bars are suddenly greatly increased in strength. In most cases, the bus structure design includes parallel bars for each phase, with the current flow in the design being unidirectional. Because power flow is unidirectional, the magnetic fields oppose each other in this arrangement, during a fault condition there are sudden very large mechanical vibrating forces applied to the bus bar assembly due to these magnetic fields. If a bus structure is not braced appropriately for the level of available fault current and a low impedance fault occurs, the switchgear will be severely damaged or destroyed. The forces involved are often large enough that damage is not limited to the equipment itself, but often extends to the facility around it. A bracing rating typically depends on the type of bracing materials used, the distance between bracing points, the rigidity of the bus material, and the practices used to connect power conductors to the structure.

While it is common practice to define bracing requirements based on three phase fault conditions, it must be noted that in a typical synchronous generator set application the fault current levels can be considerably higher for a single phase fault than a three phase fault. Further, if generator sets are paralleled to the utility/mains grid, the fault capability of the utility/mains and the generator sets must be summed to determine the worst case conditions defining bracing requirements for a typical system.

Industry standards exist for bracing practices for bus structures to meet specific fault current levels using components of recognized strength that are applied properly. In critical facilities, it is desirable to prototype test a bus structure under actual fault conditions to verify that the structure will survive a fault condition and be safe to operate after the fault occurs.

See **Section 4.5.4 on page 74** and Cummins Power Generation's *T-030 Liquid Cooled Generator Sets Application Manual* (available at www.cumminspower.com) for more information on ratings and calculations for fault current levels from generator sets.

4.5.3 Device Ratings

The current carrying/switching equipment in a switchboard (including molded case circuit breakers, insulated case circuit breakers, power circuit breakers, contactors, and fuses) also will have steady state and short circuit ratings.

The steady state rating of molded case circuit breakers is often limited to 80% of the nameplate rating, while other devices such as electronic solid state trips can be continuously rated; that is, able to carry 100% of their nameplate rating for any time duration. Again, it is incumbent on the system designer to verify that the ratings are appropriate based on the power supplied and consumed in the facility.

The short circuit rating of various switching and protective devices varies dramatically. Care must be taken to apply devices within their ratings in all cases, because the consequence of misapplication can be catastrophic failure of the device and damage to the surrounding structure/equipment under fault conditions. Again, note that selections for specific devices should consider the worst case fault conditions, which may be a single phase fault for synchronous generators. Note also that in systems that have multiple sources connected in parallel consideration must be given to how the sources can direct current to a specific location in the distribution system.

It should be noted that in general when any circuit breaker or fuse is subjected to a fault at the highest limit of its ratings, it is typically seriously damaged, and should be replaced at the earliest opportunity.

Circuit breakers, in addition to their steady state rating, will also have either an interrupting rating or a withstand rating. In general, devices that have interrupting ratings are designed to open as quickly as possible under high magnitude fault conditions, to provide best possible protection to downstream equipment, and also to protect the device itself. Devices that have withstand ratings are designed to operate safely with high magnitude fault currents for a defined period of time, for example 30 electrical cycles, and then safely clear the fault.

Fuses typically will clear high magnitude faults very quickly (within a fraction of an electrical cycle). As a consequence of this, they provide excellent protection for distribution equipment. The negative of the design is that they do have the weakness of requiring replacement if a significant fault occurs, and in many cases of leaving the loads connected to a source that as a single phase failed.

Contactors typically have very low fault current capability. Consequently, if they are used in distribution or paralleling applications they are commonly protected by fuses. Care should be taken to maintain a local inventory of fuses so that a generator set is not disabled by fuse availability; and an appropriate switchboard/switchgear design should be used, recognizing that the fuses may require changing while the switchboard/switchgear equipment is energized. Note that an imbalance in the ability of the equipment to accurately transport current on all three phases may disrupt operation of the load sharing system and cause generator set or system failure.

Dedicated purpose transfer switches (that is, devices that are specifically designed to be transfer switches versus transfer switches built from contactors or circuit breakers) will have “withstand and closing” ratings. These ratings are somewhat more stringent than “interrupting” or “withstand” ratings because the equipment is required to not only safely clear a fault, but also then close into a fault and still not cause a mechanical or electrical hazard. However, in contrast to switchboard/switchgear short circuit performance, transfer switches may be approved or listed to appropriate standards and still be seriously damaged under high magnitude fault conditions. See Cummins Power Generation's *T-011 Automatic Power Transfer Systems Application Manual* (available at www.cumminspower.com) for more information on transfer device ratings and practices.

4.5.4 Estimating Available Fault Current

It is critical that the designer verifies the level of available fault current in the system, and specifies equipment that will be suitable for the application. Since the switchgear equipment is critical facility infrastructure that will last for the life of the facility, it is important that the decisions in this area consider the potential for future growth.

In utility distribution systems, a rough estimate of the available fault current can be determined by dividing the transformer steady state rating (amps) by the impedance of the transformer. For example, a 1000 kVA/480 VAC, 5.75% impedance transformer would be capable of delivering approximately 21,000 amps of fault current into load circuits.

The available fault current from a generator set on a 3-phase bolted fault is roughly the steady state ampacity rating of the generator, divided by the subtransient reactance of the machine at that rating. For a 1000 kW/480 VAC machine with 12% subtransient reactance, the available fault current at the terminals of the generator is approximately 12,500 amps. If this generator set is paralleled with two other identical machines, the total available from all generator sets is the sum of the available current from each machine, or 37,500 amps.

In a paralleling system, the available fault current at the paralleling equipment is the sum of the available current from all sources that are simultaneously connected to a common point in the system. So, if three generator sets are paralleled to the utility, the bracing level required at the switchboard/switchgear equipment where they are connected would be the sum of the fault current from all generators plus the utility/mains contribution. Note that motors running in the distribution system can also contribute to the available fault current (for both normal and emergency distribution systems). If no other information is available, a 10% allowance for motor load generator fault current is often used as an estimate of impact.

In generator set installations it is critical to understand the “worst case” condition for fault current at any point in the distribution system. This is impacted by the locations where the sources are connected, and also by the fact that single phase fault current is considerably higher in synchronous generators than three phase fault current.

See T-030, the Cummins Generator Application manual for more information on ratings and calculations for fault current levels for generator sets (available at www.cumminspower.com).

4.5.5 Derating Practices

While it is common practice and widely understood that engine-driven generator sets have varying ability to carry load with increasing altitude and/or temperature, it is not widely recognized that circuit breakers and switchgear also may require derating to operate successfully for a long and safe life, especially when they are used in severe environments or at high load or duty cycle levels.

As noted previously, as current flow increases in a conductor, heating increases; and as the ambient temperature around an electrical device increases, it becomes more difficult for the device to reject all the heat produced by current flow. So, if the ambient temperature is higher than the equipment is rated to handle, the magnitude of current flow must be reduced in order for the equipment to operate at safe temperature levels, and to prevent nuisance tripping of circuit breaker trip units or protective relaying, or damage to the components themselves.

When electrical equipment is taken into more severe environments with higher temperatures and higher altitudes, it is necessary to verify the rating of the equipment (switchgear and breakers) based on the conditions at the installation site, because the higher altitudes impede the effectiveness of air cooling designs because of the decreased air density. Higher ambient temperatures and elevations also affect dielectric strength, insulation ratings, and maximum allowable service voltage. See the tables below for typical derating recommendations.

Circuit breaker derating practice varies with the manufacturer and the performance certifying agency requirements. In general, molded case circuit breakers and power circuit breakers are designed for operation at full load in ambient temperatures of up to 40 °C (104 °F). Some devices, such as some molded case breakers with thermal-magnetic trip units, are limited to 80% of their nameplate current rating under steady state operation, regardless of the ambient temperature. The 40C design point is often problematic for generator set applications, because with the high heat rejection levels of generator sets, switchboard equipment in generator set rooms or enclosures is more likely to operate under high ambient conditions.

TABLE 8. ANSI SWITCHGEAR ALTITUDE CORRECTION FACTORS

Altitude (m)	Voltage	Current
2,000m and below	1.00	1.00
2,600m	0.95	0.99
3,900m	0.80	0.96

TABLE 9. ANSI SWITCHGEAR TEMPERATURE CORRECTION FACTORS

Ambient Temperature (°C)	Derating Factor
40	1.00
45	0.95
50	0.89
55	0.84
60	0.77
65	0.71
70	0.63

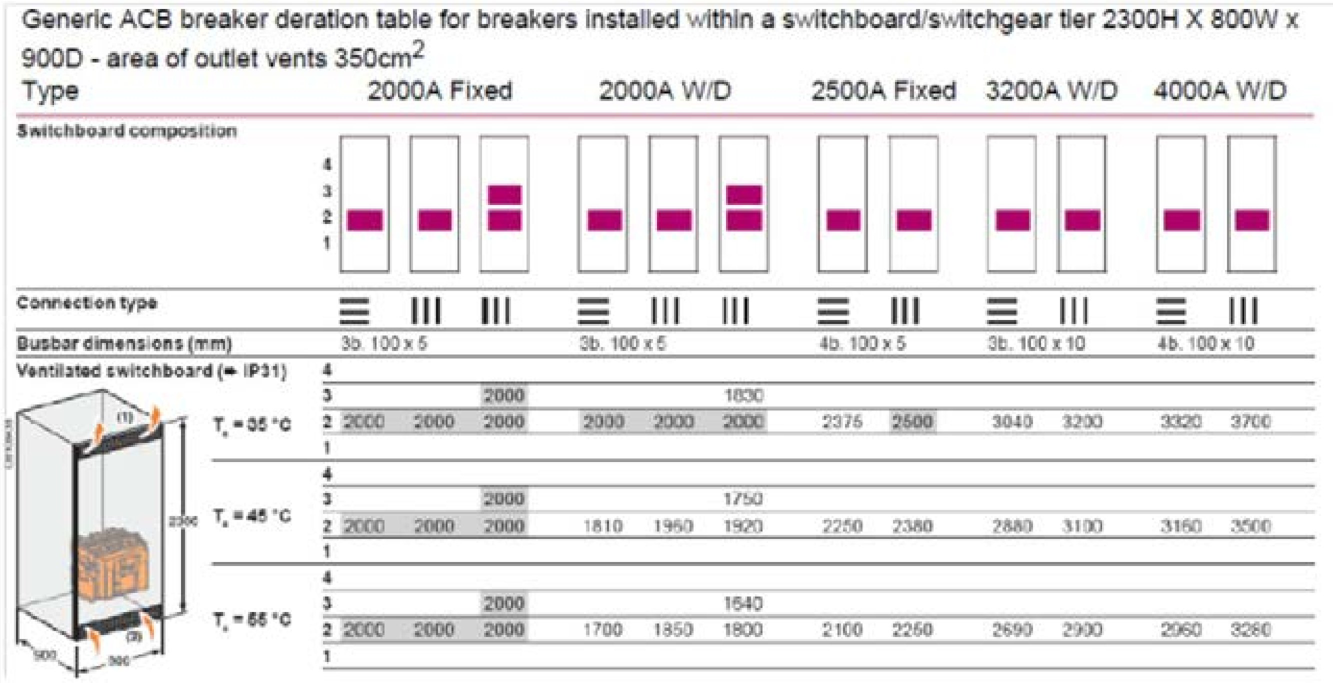
TABLE 10. TYPICAL DERATING FACTORS FOR CIRCUIT BREAKERS DUE TO ALTITUDE (IEC BREAKER MANUFACTURER)

Altitude (Meters)	Dielectric (volts)	Rated Insulation Voltage	Maximum Service Voltage	Thermal Rating at 40C (x I)
Under 2000	3500	1000	660	1
3000	3150	900	590	.99
4000	2500	700	520	.96
5000	2100	600	460	.94

In more difficult environments, special considerations and design features may be necessary to achieve optimum system performance at lowest cost. For example, ventilation or even air conditioning in switchgear rooms may be desirable. Where these means are not practical (such as in a generator room), the only viable solutions may be to either move the more sensitive equipment out of the generator room, or derate the electrical equipment as recommended by the manufacturer to avoid the reduction in system life and other hazards previously mentioned.

Derating requirements for applications required to be compliant to IEC require additional considerations.

The derating practice for specific switchboard/switchgear designs and specific structures can be very complex, as the temperature rise within the structure and the components varies considerably with the design of the structure, especially as more insulation/barriers are used. The figure below shows a derating instruction for one manufacturer with specific breaker products:



Generic ACB breaker deration table for breakers installed within a switchboard/switchgear tier 2300H X 800W x 900D - area of outlet vents 350cm2

Type		2000A Fixed			2000A W/D			2500A Fixed		3200A W/D		4000A W/D	
Connection type		☰	III	III	☰	III	III	☰	III	☰	III	☰	III
Busbar dimensions (mm)		3b. 100 x 5			3b. 100 x 5			4b. 100 x 5		3b. 100 x 10		4b. 100 x 10	
Ventilated switchboard (⇒ IP31) T_a = 35 °C	4												
	3			2000			1830						
	2	2000	2000	2000	2000	2000	2000	2375	2500	3040	3200	3320	3700
	1												
T_a = 45 °C	4												
	3			2000			1750						
	2	2000	2000	2000	1810	1960	1920	2250	2380	2880	3100	3160	3500
	1												
T_a = 55 °C	4												
	3			2000			1640						
	2	2000	2000	2000	1700	1850	1800	2100	2250	2690	2900	2960	3280
	1												

FIGURE 31. TYPICAL DERATING INSTRUCTIONS FOR AN IEC SWITCHBOARD. NOTE REQUIRMENTS ASSUMING AN ENCLOSURE TIER SIZE IS 2300 MM X 800 MM X 900 MM - AREA OF OUTLET VENTS: 35 CM2

4.5.6 Determination of Required Equipment Main Bus Rating

The assumption that the steady state bus rating should be equal to the capacity of all the connected generator sets and other sources will often result in very large bus structures which are unnecessarily expensive and may not be commercially available.

The required rating of a switchboard bus is based on the sum of the maximum steady state ampacity of all the connected sources, and the sizes and distribution of load devices connected to the sources. It also depends on the current flow paths between the sources and the loads. So, a process of analysis is necessary to select the optimum cross bus and riser (or risers) size for a switchboard/switchgear line up, and the location of load devices in the switchboard/switchgear structure. The engineering process to perform this analysis is called “bus optimization”.

4.5.7 Optimization Of Switchboards/Switchgear

Optimization of switchboards/switchgear occurs when there is a review the bus ratings and physical arrangement if the device in the equipment to be sure that the equipment is the smallest possible physical size and lowest cost that is consistent with the required equipment ratings. The bus rating is not necessarily the sum of all the ratings of all the sources, and there is not necessarily a specific combination of breakers that can be used in each section.

The switchgear bus size is not necessarily the sum of the output ratings of all the sources connected to the bus. In fact, in most situations where there are multiple sources connected to a single bus, the bus size can be optimized by careful location of the components. This design practice has no negative impacts, will significantly reduce cost and can also be used to address bus temperature limitations.

The physical layout of the equipment plays a major role in sizing the main bus through the optimization process. The physical relationship between where the distribution components, the utility (when paralleled to generator sets) and the generator set paralleling breakers are connected to the main bus impact the minimum size requirement of the main bus. The major point to remember is that the bus current flow can be constrained by the limitation of the sources or limitations in load circuits.

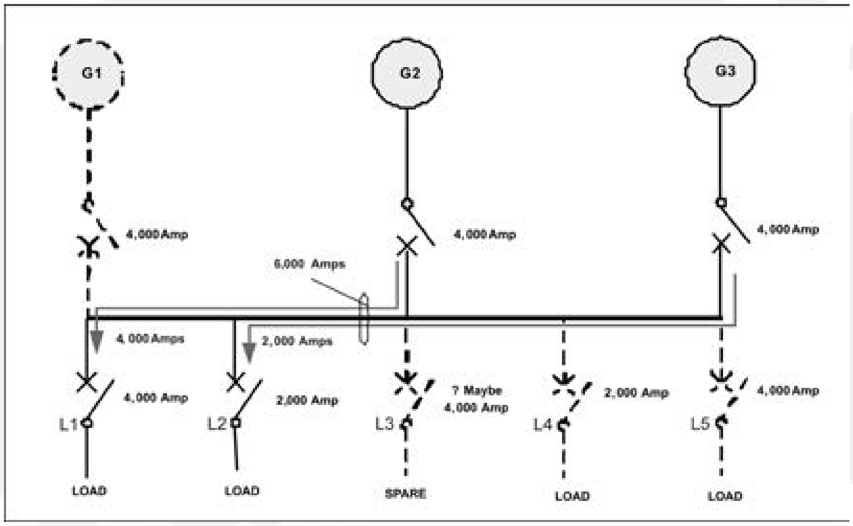


FIGURE 32. PARALLELED GENERATOR SETS FEEDING A 4000 AMP BUS.

The example below (**Figure 33**) shows a paralleling system consisting of two 1500 kW, 480 VAC, 60 Hz generator sets and 4000 amps of load.

The generator sets are balanced and will share the load equally. If the continuous load is 4000 amps, each generator set will supply up to 2000 amps to the load. The current at point A is 4000 amps. If G1 is not operating, then G2 will be carrying the entire load, and its output is limited by the 4000A main breaker to a maximum of 4000 amps on a continuous basis. It is also limited by the G2 breaker to a maximum of 2500 amps. Therefore the minimum bus size required for this system is 4000 amps.

Suppose the loads are split into two equal distribution sections as shown in **Figure 33** below. The result is the same as if there were a single 4000A breaker since the main bus must carry 4000 amps at point A.

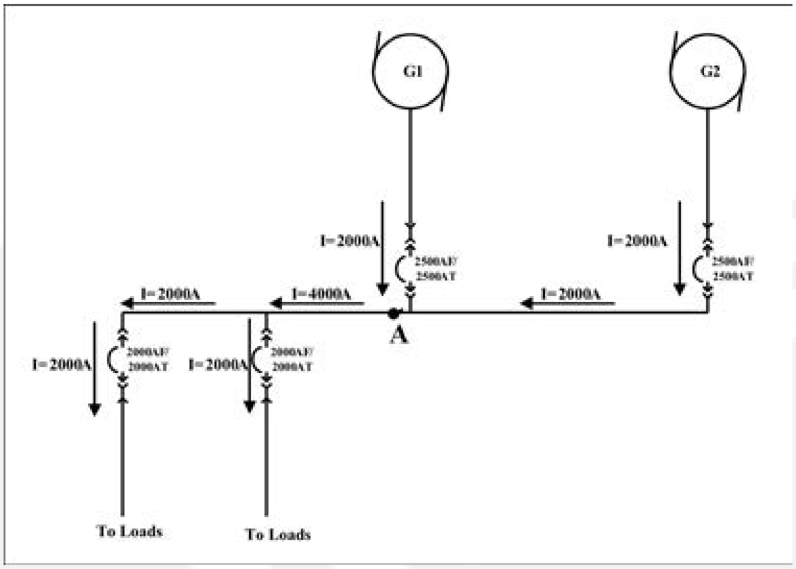


FIGURE 33. PARALLELED GENERATOR SETS FEEDING A 4000 AMP BUS WITH SPLIT LOADS.

If the two loads are connected as shown in **Figure 34** below, continuous full load current is drawn to both ends of the bus and does not exceed 2000 amps at points A or B since the maximum load at those points is 2000 amps. The minimum allowable bus size for this system configuration is 2000 amps.

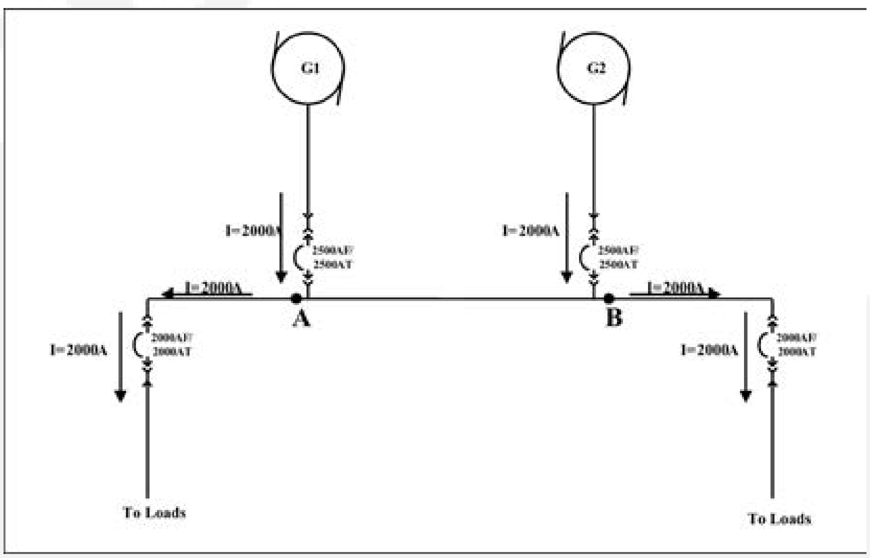


FIGURE 34. PARALLELED GENERATOR SETS FEEDING A 2000 AMP BUS.

Suppose G1 shuts down and the system goes through a load shedding sequence so that G2 can continue to support up to 2255 amps of load (**Figure 35**). The maximum continuous current flow through the bus will be at point B will be $\leq$ 2000 amps depending what loads remain connected to the system. The current flow at point A $\leq$ 2000 amps, since each distribution section is limited by its feeder breaker size to 2000 amps. Since the generator set can provide up to 2255 amps, it is possible that the riser bus might need to carry up to 2255 amps. This might drive the entire system to a larger bus size.

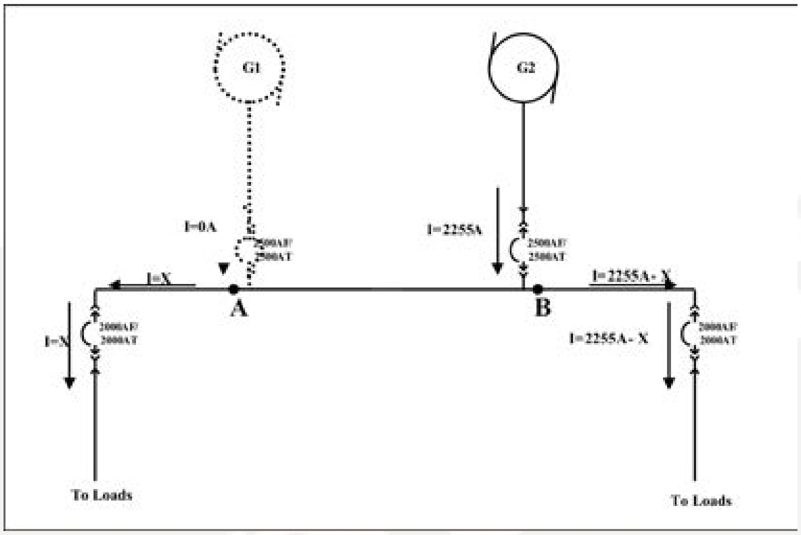


FIGURE 35. PARALLELED GENERATOR SETS WITH ONE GENERATOR SHUT DOWN.

Now, consider an example that shows the true benefits of switchboard/switchgear optimization:

The customer's single line (**Figure 36**) calls for a main bus bar rating of 13,500 amps (three 1750kW/380 VAC generator sets at 3323 amps each for a total of 9970 amps capacity, with margin for overload). That is a lot of copper.

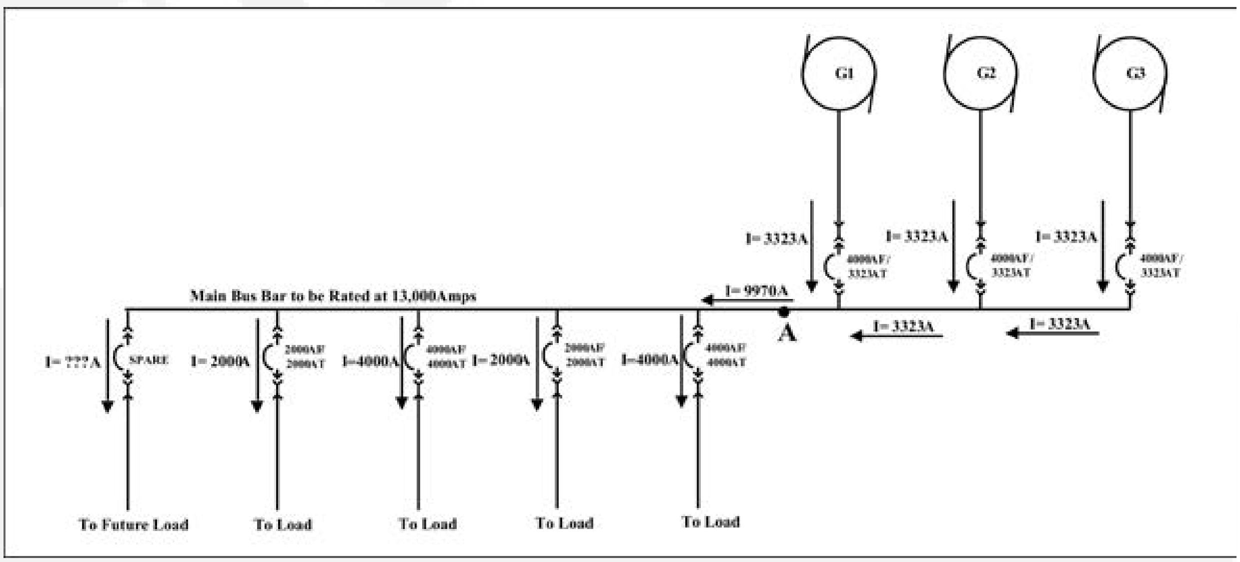


FIGURE 36. MEDIUM VOLTAGE GENERATORS IN PARALLEL.

Rule 1: You can never pull more current out of a switchboard/switchgear than you put in. The current flow within the switchboard/switchgear decides the size of the main bus bar system. For ease of understanding, let's assume that each of the generators can provide 4000 amps of capacity.

What if the switchboard/switchgear is built as follows?

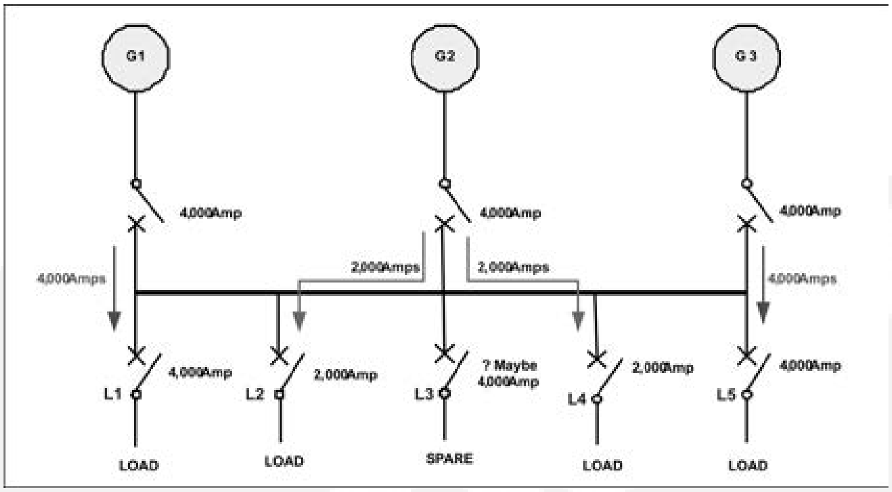


FIGURE 37. MEDIUM VOLTAGE GENERATORS IN PARALLEL WITH AN OPTIMIZED BUS.

With 12,000 amps in and 12,000 amps out, based on everything working correctly all the time the main bus would only need to be 2,000 Amps.

The trouble is that systems do not work perfectly all the time.

As you can see **Figure 38**, if G1 fails and L4 and L5 trip, the current flow in the main bus will now be 6,000 amps. (4000 amps in the far left feeder plus 2000 amps in the next feeder.) So the bus to the right of the 2000 amp feeder must be capable of 6000 amps.

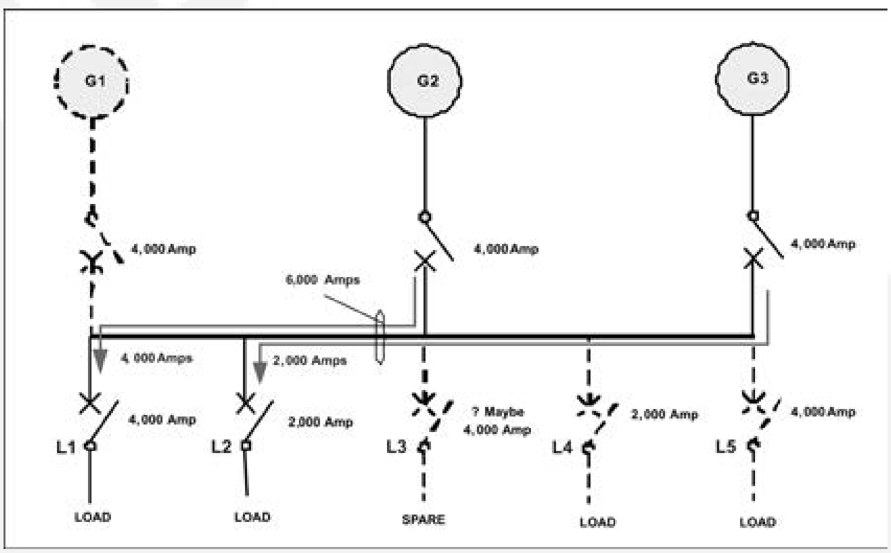


FIGURE 38. MEDUIM VOLTAGE GENERATORS IN PARALLEL WITH ONE GENERATOR FAILED.

Thus optimization requires the bus bar system to be evaluated for the worst case scenario (see **Figure 38**). Careful review of the system will result in the understanding that each generator riser is limited to 4000 amps by its paralleling breaker, and the left and right sides of generator 2 have a maximum of 6000 amps of load.

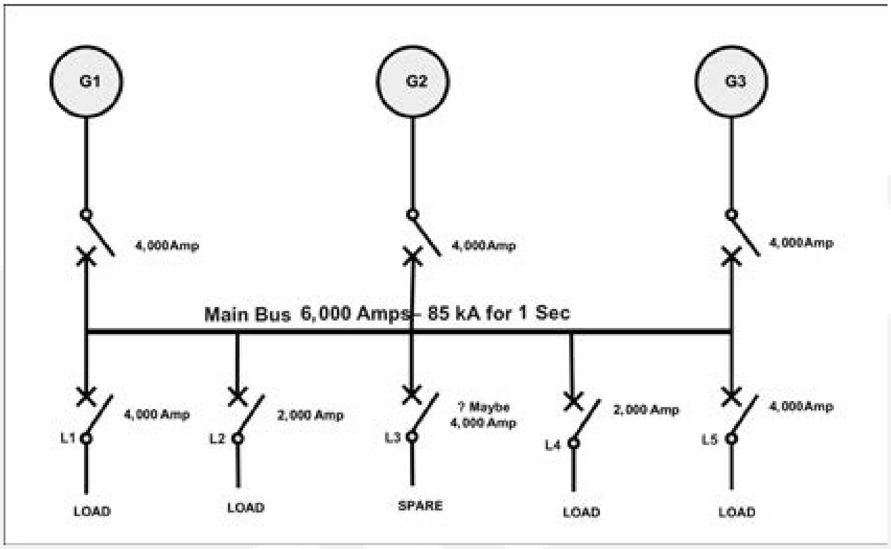


FIGURE 39. MEDIUM VOLTAGE GENERATORS IN PARALLEL WITH PROPERLY SIZED, OPTIMIZED BUS.

With the use of optimisation we have gone from a single line requiring a main bus system of 13,500 amps to an optimised switchboard design that only requires a 6,000 amp bus (see **Figure 39**) thus reducing the amount of copper required to build the switchboard/switchgear and subsequently the cost.

4.5.7.1 Bus Tie/Coupler Use And Application

Bus ties/couplers are utilized within a power distribution system to enhance the flexibility of power source options servicing critical facility loads. These devices are installed within the switchboard/switchgear line up. Depending on the complexity of the system these bus tie/couplers are either automatically or manually operated. When manually operated a key interlocking system such as Kirk Key (NEMA) or Castell Key (IEC) system is employed to ensure operator and system integrity.

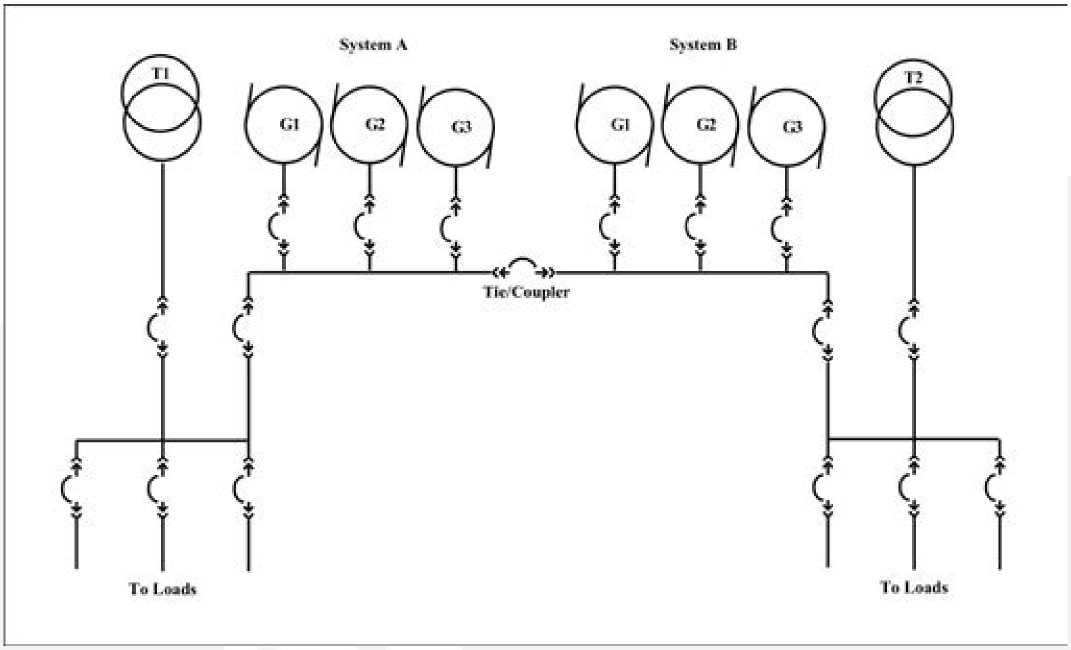


FIGURE 40. TYPICAL FULLY FLEXIBLE POWER DISTRIBUTION SYSTEM INCORPORATING A BUS TIE/COUPLER.

In the figure above (Figure 40) the bus tie/coupler provides a power flow connection between system A and system B. Should the Utility supply fail to T1 and a generator set or all of the generator sets in system A fail to start then the bus tie/coupler would be closed and the loads of system A will be powered by the appropriate number of generator sets of system B. The design is such that both system A and B support each other or a combination of either can be utilized to ensure that the maximum number of critical loads are supported at any time.

Well-engineered power system designs incorporating the use of one or numerous bus tie/couplers offer the ultimate in versatility of powering and maintaining power to critical loads within a facility, however poorly engineered solutions actually diminish the maintainability of many systems. As can be seen in the figure below (Figure 41) the engineer has removed the main generator output bus breakers. While the systems will still support one another and the engineer has saved the end user a few dollars on the capital cost of the breakers and their installation, the engineer has also removed the ability to service and maintain the two generator bus systems and the bus tie/coupler without removing power to 50% of the facility.

Note that the design utilizes a utility main breaker for each utility/mains source and a generator bus main breaker for each utility breaker. Thus the utility main and generator bus main breakers form a transfer pair that can be automated using power transfer controls that are common off-the-shelf products of many suppliers, thus reducing engineering cost while improving reliability and serviceability.

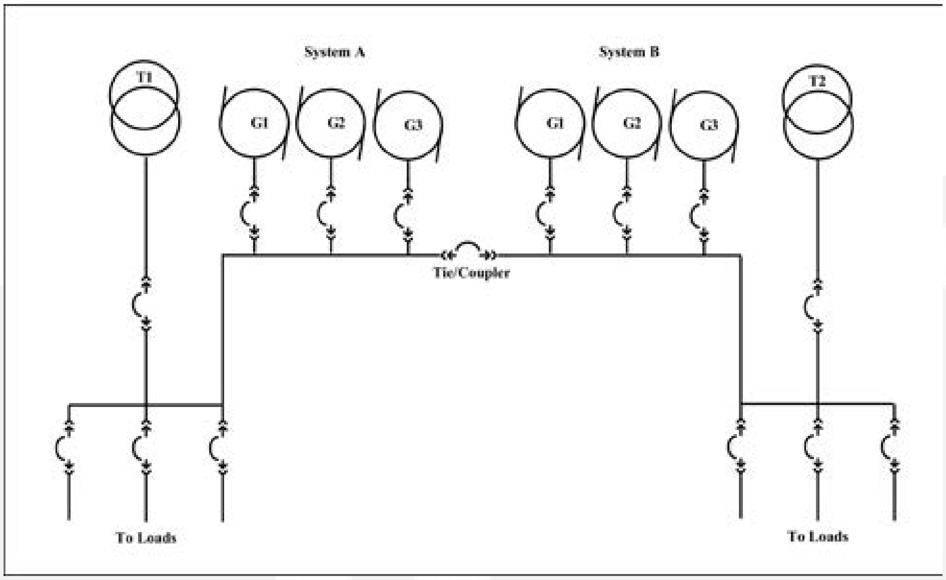


FIGURE 41. TYPICAL POWER DISTRIBUTION SYSTEM INCORPORATING A BUS TIE/COUPLER BUT NO GENERATOR BUS OUTPUT BREAKERS (GM).

4.6 Circuit Breaker Characteristics

The purpose of circuit breakers is to protect downstream cable and equipment from excessive current flow, usually caused by faults. The National Electrical Code (NEC) indentifies two types of overcurrent conditions, overload and short circuit. The two terms are often used interchangeably but they do have separate meaning and separate conditions.

An overload condition refers to current flowing in a normal current path that is in excess of the rating of the conductor. A motor that fails to start and is drawing locked rotor current for an extended period of time is an example of an overload condition. An overload condition can cause deterioration of the insulation system which in time could result in a short circuit.

An overcurrent or short circuit condition refers to a high level of current flowing in an abnormal current path. Often this is caused by the conductors of two different phases coming into contact or one phase coming into contact with neutral or ground. Because the impedance of this condition is so low, a large amount of current flows relative to the normal operating current. This high current flow generates mechanical stresses on the equipment and heat very quickly and can lead to almost immediate equipment damage if not interrupted.

Note that there are three major classes of circuit breakers: molded case, insulated case, and ANSI/power breakers. In North America UL 489 is the governing standard for molded case and insulated case breakers and UL 1066 and ANSI C37-13 are the governing standards for power breakers.

The different classes of breakers are distinguished by how fast they clear faults, how long they can provide fault current to downstream devices and the level of repair-ability in the breaker design. These characteristics drive how they are used in facility distribution system design. (See table below.)

TABLE 11. CIRCUIT BREAKER CHARACTERISTICS

	Molded Case	Insulated Case	Power Air
Electric Operator	optional	*	*
5-Cycle Closing Capability	A few	*	*
Durable Electric Operator		*	*
Drawout Available		*	*
Solid State Trip	optional	*	*
Instantaneous Trips	Standard	Standard (may be time delayed)	optional

Breakers generally provided in different frame sizes. Several current ratings are provided within a single frame rating. A current sensor is used to define different breaker ratings in a single frame size.

Circuit breakers for 3-phase power distribution systems may have either 3-switched poles (most common) or 4-switched poles. Based on the grounding and bonding arrangement in the distribution system provided, 4-switched poles may be required. See Section 7.3 on page 204 for more information on this topic.

4.6.1 Molded Case Circuit Breaker

Molded case circuit breakers are inexpensive and reliable overcurrent protection devices. They are designed to clear faults quickly, and if they are subjected to a fault condition they often require replacement, since they are not repairable. Because their electrical operators are relatively slow, molded case circuit breakers are not suitable for operation as paralleling breakers in random access (active synchronizing) paralleling systems. However, they are well suited for use in automatic exciter paralleling systems and as distribution devices where they are normally closed and automatically operate only on a fault condition.

Molded case breakers are normally provided with simple thermal-magnetic trip units, which may not offer sufficient flexibility to coordinate the emergency distribution system. Consideration should be given to specifying electronic trip units to allow more flexibility in system coordination.

Molded case breakers are usually used for branch circuit/sub-main protection (i.e., installation at the “bottom” of a distribution system) close to the loads that they protect. These breakers typically have simpler trip units, (see Section 4.6.6.2 on page 89 for more info) and are available over a broad range of frame sizes. UL 489 is typically used for certification of performance in applications in the U.S.A.

Molded case breakers are not required to be continuously rated. The most common practice, particularly when using thermal-magnetic trip units, is for use of an 80% rating for continuous service up in applications up to 40 ˚C.

Major components common in circuit breakers include:

- A rating plug used with a specific sensor to allow use in lower current applications. For example: 800AF breaker can have 400 amp sensor, and rating plugs to drop actual rating from 400 amp to 250, 150, or 125 amp.

- Electrical Contacts: The electrical contacts act as the switch inside the breaker. When the contacts are touching, current can flow. When the breaker trips or is manually de-energized these contacts spread apart, preventing current flow. The moveable portion of the contact assembly uses an arm-like device called a blade to move the contact from open to closed. On some breakers the contact assembly includes both a current carrying contact and an arcing contact that is used to help extinguish the arc that occurs on operation. A pigtail often formed or braided copper or aluminum provides the mechanical isolation between the stationary and moving parts of the assembly.
- Arc Extinguisher: An arc is created when the contacts of a breaker are separated under electrical load. The intense heat produced by this arc could damage or even destroy a breaker if not managed. The arc extinguisher (also called arc chute) divides, elongates and cools the arc so that damage does not occur.
- Poles: The number of poles a breaker has refers to the number of circuits that are switched. In industrial applications 3 poles are most common, switching all 3 phases, however in some applications it is necessary to switch the neutral circuit as well, which will require a 4 pole circuit breaker.

Typical construction of a molded case circuit breaker is shown in the figure below.

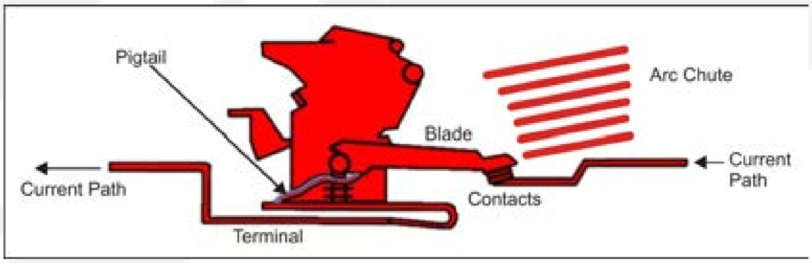


FIGURE 42. TYPICAL CONSTRUCTION OF A MOLDED CASE CIRCUIT BREAKER.

4.6.2 Miniature Circuit Breakers

Miniature circuit breakers are typically much smaller devices designed for high density, group mounted applications. These devices can be built to UL 489 or IEC standards and typically are available from 1A to 150A in size. The IEC standards consist of 3 MCB types; a type B, type C and type D which indicates the speed and full load current at which they trip. These devices can either contain a combination thermal/magnetic trip unit or just a magnetic trip unit design to trip on high inrush current only. The magnetic only devices are usually used in combination with thermal protection devices such as motor starters.

FIGURE 43. MINIATURE MOLDED CASE CIRCUIT BREAKER

4.6.3 Power Air Circuit Breaker

Power air circuit breakers are rugged, heavy duty devices that are specifically designed for switching and protection. Because air is the medium of electrical insulation between parts, these breakers are larger and more expensive than molded case breakers with comparable ratings. Power air circuit breakers incorporate a fast (5-cycle) closing time, which is necessary in random access paralleling systems or any system that requires use of an active synchronizer.

Power air breakers by contrast are designed to be field repaired, and designed to carry short circuit current for a relatively long time (up to half a second), so that downstream devices can clear and faults can be isolated from the balance of the system. Often provided in draw out carriages; they are typically provided at the “top” of a distribution system. Power air breakers come in limited frame sizes, typically 800 amp at smallest, but available up to 4000 amp (UL)/6300 amp (IEC). They typically use a stored energy closing mechanism in which a motor cranks up (charges) a spring and spring energy closes the contacts. The spring also forces the contacts closed so the contact does not arc and have as much damage. UL 1066 is used for certification of performance in the U.S.A.

Power air breakers offer considerably higher withstand and interrupting ratings than most molded case devices and incorporate reliable 5-cycle switching mechanisms, which make them desirable for emergency switching operations. Also, most power air breakers are provided with electronic trip units that allow the designer the most flexibility in setting the breakers for proper system coordination, including the ability to eliminate an instantaneous trip characteristic.

4.6.4 Insulated Case Power Circuit Breaker

Insulated case power circuit breakers are similar in design to power air circuit breakers. They are also rugged, heavy duty devices that are intended to function as switches in addition to providing protective functions. The major difference is that a molded insulated case encloses the mechanism, making them similar in appearance to molded case circuit breakers. Insulated case power circuit breakers also incorporate a fast (5-cycle) closing time.

Insulated case breakers have characteristics of both molded case and power air breakers. They can be thought of as a power breaker in a molded case. Insulated case breakers can be listed as a power breaker or molded case breaker, but are not as repairable as a power breaker. They are often considered to be less heavy duty than power breaker, but can be rated to similar levels and are often used throughout a distribution system. They are less expensive than power air breakers, so often replaces the power air device in cost-conscious designs.

Trip units are similar to those offered in power circuit breakers, but generally they do not have the ability to survive a fault for as long a duration as power air breakers, so they may have time delayed instantaneous functions, but will not include the ability to turn off the instantaneous trip function.

TABLE 12. NORTH AMERICAN STANDARDS AND ENDURANCE CAPABILITIES FOR CIRCUIT BREAKERS

	ANSI C37.13/UL 1066 **Power Air or Insulated Case**	**UL 489** **Molded Case or Insulated Case**
Mechanical Endurance	• 500 drawout operations • 4000A frame 1500 open/close operations; maintenance intervals every 250 operations • 800A frame 12500 open/close operations; maintenance intervals every 1750 operations	• 4000A frame 1500 open/close operations • 800A frame 3500 open/close operations • No maintenance intervals
Electrical Endurance	• 4000A frame 400 open/close under load • 800A frame 2800 open/close under load	• 6000A frame 400 open/close under load • 800A frame 500 open/close under load

Note the testing cycles for opening and closing operation. Paralleling devices open and close many times more than most breaker applications, so it is necessary to keep close track of the number of opening and closing cycles to be sure that the device is fully operational throughout its required life span. Note that the open and close cycles in these charts are typically done under load, which is a more strenuous situation than no load. When the paralleling controller operates the breaker at no load the life span of a breaker is enhanced.

TABLE 13. CIRCUIT BREAKER MANUFACTURERS AND TRADE NAMES

Manufacturer	**ANSI C37.13/UL 1066** **Power Air CB**	**UL 489** **Insulated Case**
ABB	K-Line	N/A
Eaton	Magnum DS and DSII	SPB
General Electric	Wave Pro	PowerBreak II
Square D	DSII, MasterPact	SE, MasterPact

TABLE 14. IEC: CIRCUIT BREAKER MANUFACTURERS AND TRADE NAMES

Manufacturer	**Power Air Breakers**	**Molded Case**
ABB	Emax	Isomax S and Tmax
Siemens	Sentron 3WL	VL
Terasaki	TemPower 2	TemBreak 2
LG	Ace-MEC	Series GB-AB
Schneider Electric	Masterpac	Compact NSX

4.6.5 Motor Starting Contactors For Paralleling Devices

In some applications motor starting contactors are used instead of breakers for paralleling. This is most often done in situations where small generators are being paralleled and the application is very cost sensitive. There is no inherent reason why contactors cannot be used instead of breakers, however the protection and disconnect provisions that a breaker provides will have to be provided in some other way. In general, protection will be required to be accomplished through the use of fuses, since contactors do not typically have appropriate short circuit ratings for paralleling applications.

4.6.6 Circuit Breaker Optional Features and Uses

4.6.6.1 Cable Connection Provisions

Power circuit breakers and insulated case circuit breakers can be provided with either mechanical or compression lugs for connection of cable to the circuit breaker. In a mechanical connector the cable is placed in the lug and a screw assembly is used to fix the cable in the lug. In a compression assembly, a fixture and compression tool is used to permanently bind the cable to the lug, and the lug is bolted to the breaker bus connection. (See **Figure 27 on page 68**.)

Compression terminations are considered to be more reliable than mechanical lugs, because the connection from the cable to the lug is permanent and does not require maintenance. Mechanical lugs are commonly monitored for connection pressure or temperature and are typically tightened during a maintenance process at least once a year. Mechanical lugs typically take up less space, and may be less expensive to install, since they require no special tools. (The compression tool is commonly specific to each lug manufacturer.)

4.6.6.2 Protection Device: Trip Units

Low voltage circuit breakers commonly include trip units that are designed for protection of the conductors downstream from the breaker and also include provisions to protect the breaker itself from catastrophic failure when damaging current levels are present. Breaker settings in the distribution portion of the switchgear equipment are done similar to the utility/mains portion of the facility distribution system, but the paralleling breakers require further consideration. See **Chapter 6 on page 169** for more information on settings for paralleling breakers.

4.6.6.2.1 Thermal Magnetic

The most common trip units (especially on molded case breakers) are thermal-magnetic devices. The trip unit uses a bimetallic element made from two strips of dissimilar metals bonded together for the thermal element to trip the breaker open over a variable time delay depending on the magnitude of current flow through the device. A magnetic element causes the breaker to trip quickly on a high current (short circuit) condition.

Thermal-magnetic devices are the least expensive trip units used in circuit breakers. They are reliable over a long life, but are somewhat less accurate in sensing than other trip units available. They are somewhat more sensitive to nuisance tripping at high ambient temperature, and are often not rated for continuous operation at full load. See the figure below.

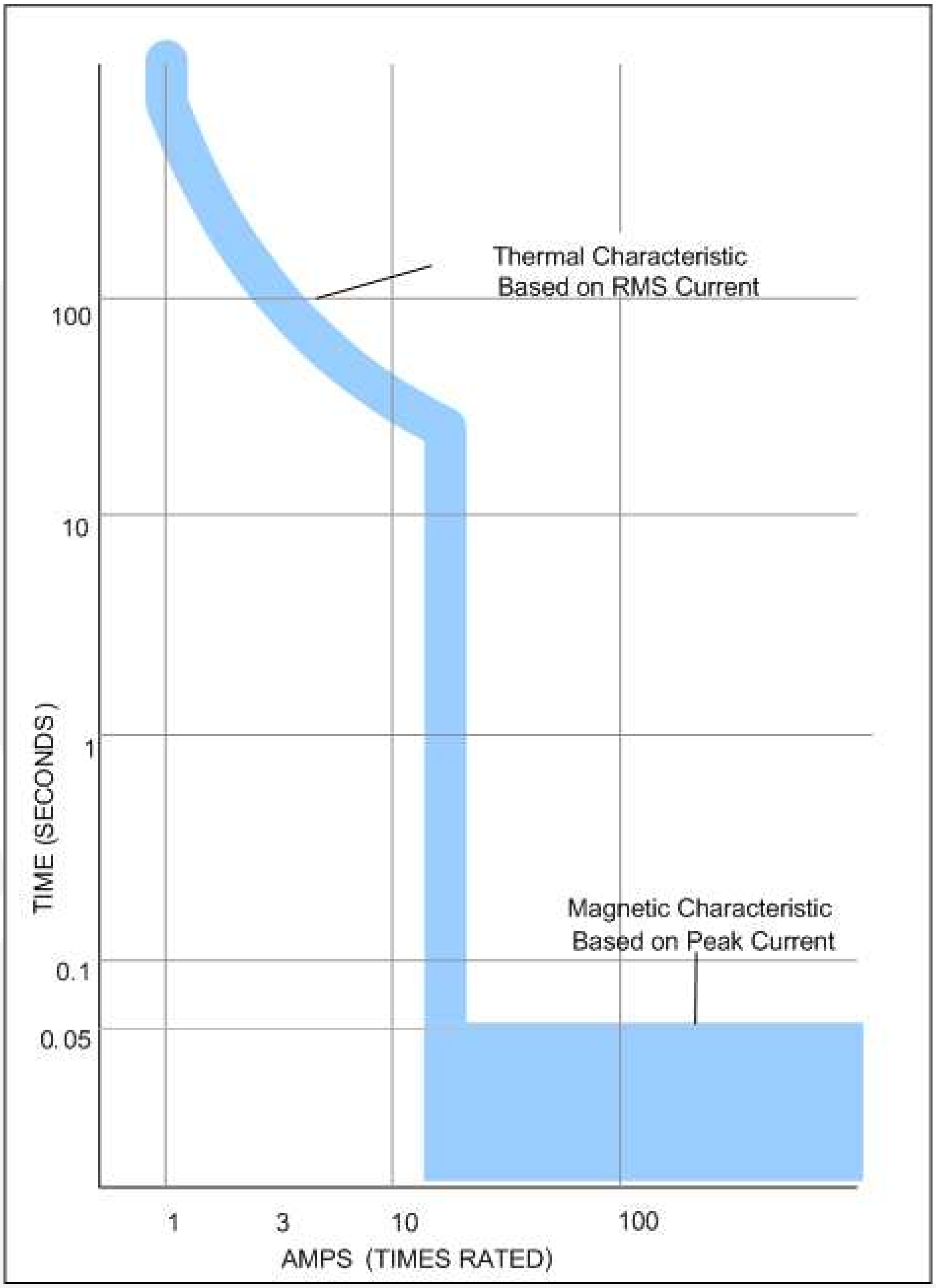


FIGURE 44. TIME OVERCURRENT CURVE FOR A THERMAL-MAGNETIC TRIP BREAKER. AT ANY TIME/CURRENT VALUE TO THE RIGHT OF THE BLUE LINE, THE BREAKER WILL TRIP. THE WIDE BLUE AREA INDICATES THAT THE BREAKER MAY TRIP IN THIS RANGE.

Thermal tripping characteristics: The thermal element consists of a bimetallic strip which trips based on an inverse time characteristic which is represented in the upper left portion of the trip curve. As the bimetal strip heats up due to excessive heat generated by the overcurrent condition one element expands more rapidly than the other, eventually causing the bimetal strip to deflect, de-latching the mechanism and mechanically causing the breaker to trip and open the circuit. The higher the current is the faster the element heats up and the faster the breaker will trip. Because the trip function is thermally based the trip time will be a function of root mean square current. Trip time will also vary with ambient temperature. It is slow acting and detects overload conditions. A typical thermal bimetallic element operation time is displayed in the figure above.

4.6.6.2.2 Magnetic Trip Element

The magnetic trip element utilizes an electromagnet with its windings in series with the load current. When a fault occurs, the magnetic field increases rapidly and actuates a magnetic armature which de-latches the mechanism, which then separates the contacts. The magnetic field response is nearly instant compared to the heating and deflection action of the bi-metallic strip, and the magnetic action is most effective at clearing short circuit faults. A typical magnetic trip element is displayed in the figure above (**Figure 44**).

4.6.6.2.3 Electronic Trip Systems

Breakers with electronic trip systems are often known as solid state circuit breakers. They typically consist of a 3-phase current transformer integral to the breaker for sensing current and a microprocessor that will activate an internal shunt trip based on a programmable trip curve. A solid state breaker may also include a rating plug which will set the ampere rating of the breaker up to the maximum allowable rating for the sensor and frame size.

Electronic trip units can include tripping characteristics beyond simple current monitoring, and include voltage protection functions.

Solid state circuit breakers have a much greater range of adjustability than other breakers. By adjusting the settings of the available trip unit functions, different trip characteristics can be achieved. This is highly desirable for critical applications where selective coordination/discrimination is required to enhance the reliability of the system. (Selective coordination is required by code for some North America applications.)

The figure below shows various discrete segments of the trip curve that can be adjusted on an electronic trip circuit breaker. The following paragraphs describe the functions, their adjustments and how they affect the trip curve.

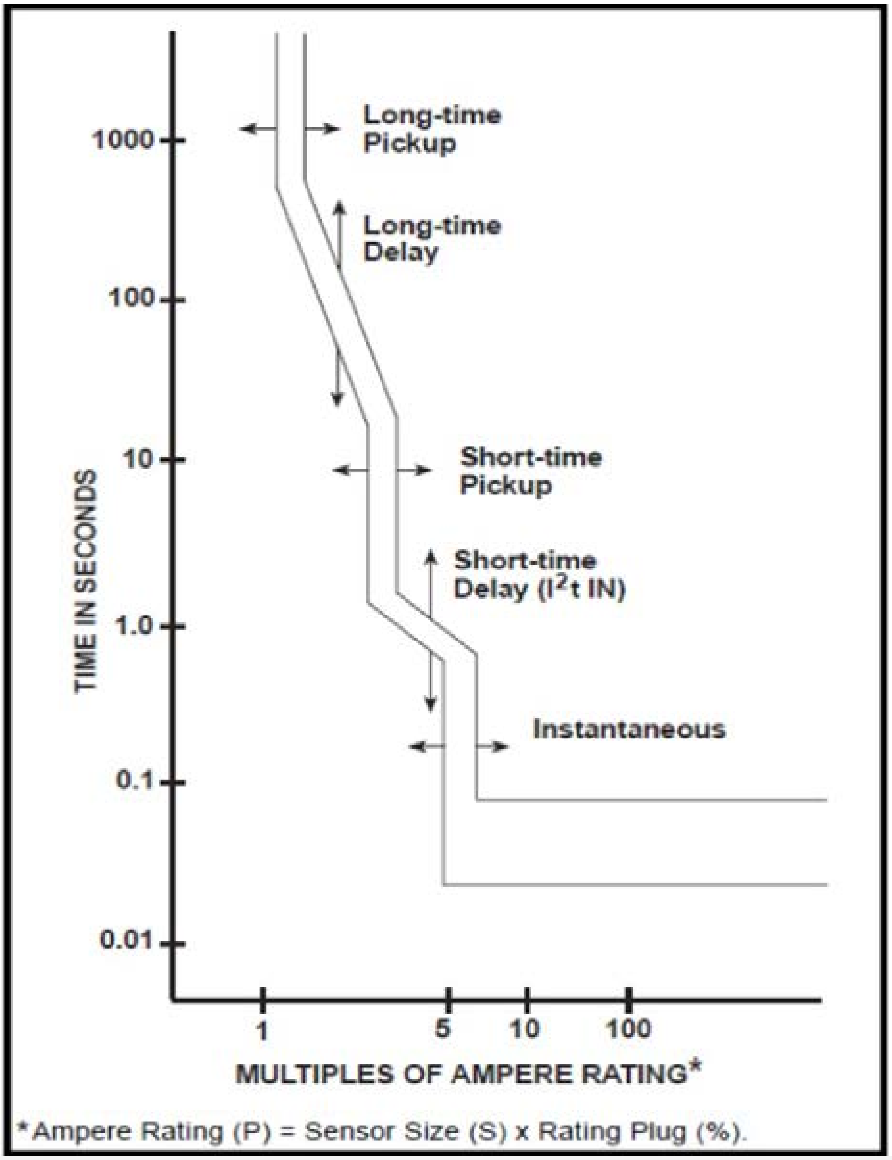


FIGURE 45. TRIP CURVE FOR TYPICAL ELECTRONIC TRIP BREAKER.

Enhanced breaker coordination is achieved by adjusting the trip curve of the breaker (see figure above); this is accomplished by adjusting the long-time, short-time and instantaneous settings found on the trip unit. The long-time function sets the maximum continuous current level the breaker will carry before it trips. The short-time trip function sets the tripping point for the short-circuit current level; this is usually some multiple of the ampere rating of the breaker trip unit. Both the long-time and short-time settings also have time delay adjustments, the user can define the length of time where the breaker will carry the overload or short-circuit before tripping. The instantaneous function also allows the user to adjust the value at which the breaker will trip on a short-circuit condition with no time delay. The adjustments available on modern electronic trip units can allow the user to fine-tune their electrical system and create a coordinated layer of protective devices allowing only the closest protective device to trip under an overload or short-circuit condition. A coordination study on the electrical system will determine the settings for the long-time, short-time and instantaneous values for the trip unit.

4.6.6.2.3.1 Long Time Pickup and Delay

This function simulates the effect of a bimetal in a thermal magnetic breaker. It reacts to overload conditions and determines how much current the breaker will carry continuously.

4.6.6.2.3.2 Short Time Pickup and Delay

This function allows the breaker to delay before tripping on high levels of overcurrent, enabling coordination with downstream breakers.

4.6.6.2.3.3 Adjustable Instantaneous Pickup

The instantaneous pickup function simulates the magnetic characteristic of a thermal magnetic breaker. This function trips the breaker with no intentional delay. Breakers will also have an instantaneous override function to trip in the event of extremely high short circuit current. This setting is typically not adjustable.

Electronic trip units can also include features beyond simple current monitoring such as power quality measurements and waveform capture. The trip units may also include provisions for remote monitoring/control, protective relay functions and maintenance features such as contact wear indication.

4.6.6.2.3.4 Zone-Selective Interlocking (ZSI)

This feature provides a positive means to assure that distribution circuit breakers in a series to a load are positively coordinated, regardless of the size or trip characteristics in the individual devices.

ZSI allows the breakers to communicate with each other so that during a fault or overload condition the device closest to the fault will ignore its preset time delays and clear the fault immediately. Eliminating the preset delays allows for quicker removal of the fault and less potential damage to the system.

4.6.6.2.3.5 Ground Fault Protection

Many trip units incorporate an option for ground fault protection. Ground fault protection operates to detect low magnitude overcurrent conditions that are coincident with an unbalance in the vectoral sum of the phase and neutral currents through a breaker (indicating that some current is flowing over the ground (earth) return path).

Ground fault protection can also be provided by separate relaying, and this may be necessary based on the nature of the system design.

See **Chapter 7 on page 203** for more information on design of systems using this protective device.

4.6.6.2.3.6 Protective Relays

In addition to the protective functions that are integral to low voltage circuit breakers, 3rd party protective relays can be used to provide redundant or more accurate protection, and add additional features not available in the breaker trip unit.

Protective relays are available in a broad range of functions and pricing levels. In general, the lowest cost, least accurate relays are termed “Industrial” grade relays. These are used for general control functions and less critical applications. “Utility” grade relays are designed to be much more accurate than industrial relays, are able to be calibrated in the field, and are designed to survive the normal stresses present on utility distribution systems, such as over voltage and radio frequency interference.

In North America, many protective relay manufacturers will list their relays to UL Category NRGU, to indicate that the relays have been tested to IEEE standards for voltage surge, radio frequency interference, and electromagnetic interference.

4.6.6.2.3.7 Protection Operation

Shunt trip - A shunt trip is a mechanical device that unlatches a circuit breaker and causes it to immediately open. In many applications this device is used to immediately open a circuit breaker on command from a protective relay.

UV release (AC/DC) - An under voltage release operates to open a breaker when the control voltage monitored (AC or DC) drops below a minimum level. The under voltage release is sometimes used to positively open the paralleling breaker if control power or AC voltage is lost. The decision to use this feature depends on an analysis of the probability of simultaneous failure of the normal opening mechanism for the paralleling breaker and the generator versus the reliability of the under voltage tripping mechanism, which if it fails, will cause the breaker to open and cannot be reclosed until repaired.

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4.6.6.3 Electrical Operation

Power circuit breakers used for paralleling functions are commonly electrically operated. Electrical operators may be either AC or DC operated. AC operators are commonly tapped to the “generator side” of each the paralleling breaker, with one tap dedicated to each paralleling breaker. The result is that each paralleling breaker has a dedicated AC operating supply, so failure of one tap will not result in total system failure, but will impact on operation of only one generator set. DC control systems may be used, but commonly depend on a single battery bank to run the system, which does result in a single point of failure in the system, which is often undesirable.

4.6.6.4 Drawout Mechanisms

Some breakers are built using a drawout construction allowing the breaker to be removed from the circuit for testing, maintenance or replacement.

Drawout mechanisms are used to allow a breaker to be connected or disconnected from a live system bus. They are usually used with paralleling and power transfer applications so that the system allows repair of a breaker without deenergizing the system. Generally the breaker rolls out on a sliding mechanism similar to a drawer, and has provisions to mechanically open the breaker before it is removed to prevent an arc from damaging the mechanical connection device on the breaker. Breakers in drawout configurations often have connected, test (auxiliary contacts operational but power contacts disconnected), disconnected (auxiliary contacts and power conductors disconnected), and removed positions. Connected is the normal position with the breaker operating. Test position allows the breaker to be electrically operated but disconnected from the AC power source in the switchboard/switchgear. Disconnected position is often still within the switchboard but disconnected from control and power. Removed position is designated to location where breaker is physically out of the enclosure.

FIGURE 46. INSULATED CASE BREAKER WITH TYPICAL DRAWOUT, SHOWN IN WITHDRAWN POSITION.

Drawout circuit breakers can be in one of four positions: they can be connected, in test, disconnected, or removed.

4.6.6.5 Optional Accessory Devices

4.6.6.5.1 Auxiliary Contacts/Relays

Auxiliary relays are commonly used to provide a remote signal describing the mechanical status of the circuit breaker. This status list can include open/closed position, and if the breaker is in the test or disconnected position,

These signals are necessary in nearly all paralleling applications for various functions. For example, a signal is required to indicate that a breaker is closed in order to switch on the load sharing controls in an isolated bus paralleling application.

Careful consideration must be given to failure modes when using auxiliary contacts, particularly to counter potential negative impacts of failed contacts versus an actual failure condition. This can be accomplished using redundant contacts, by use of monitoring logic that detects changes of state of multiple contacts, and other logic inherent in some controllers.

By North American practice, isolated contacts may be termed “a”, “b”, or “c” type contacts. “a” contacts match the device they are monitoring. For example, when an “a” contact monitors a breaker, when the breaker is closed, the “a” contact is closed. Conversely, when a “b” contact is designated, its action is opposite of the breaker. So, when the breaker is open, the “b” contact is closed. A “c” contact set indicates an “a” and a “b” contact with a common point between them.

If the aux contacts are working correctly they will always be in opposite states with respect to each other. This fact can be used to simply verify contact operation. If the A and B contacts are in the same position that will indicate that one of them is not working correctly. When the state of the breaker is unknown the control system will take some appropriate action based on the particular situation.

4.6.6.5.2 Bell Alarm Contacts

Bell alarm contacts provide a contact to indicate that the breaker trip unit has operated. Typical practice is to use a bell alarm contact to signal an auxiliary input in the generator set control and alarm the breaker trip with the generator set controller. If the paralleling breaker trips the generator breaker will usually need to be opened.

4.6.6.5.3 Padlock Provisions

Circuit breakers can generally be provided with a feature that allows them to be locked open with a padlock, so that downstream devices can be safely serviced. When a breaker is intended for use as a service disconnect, the padlock provision is commonly required.

4.6.6.5.4 Kirk-Key/Castel Keyed Locks

Kirk-key/Castel keyed locks are used on two or more breakers to control manual operation so that only a specific number of breakers can be closed at any time. They provide an effective mechanical interlock between sources, or prevent overloading of a bus by preventing closure of too many loads to a source. For example, a manual transfer function could be provided by providing kirk-key locks on two breakers connected to different sources and a common bus. With a key necessary to close a breaker, and only one key available, in order to close the open breaker the other would need to be opened, the key removed and used to close the second breaker.

4.6.6.5.5 Shunt Trip

Opens the circuit breaker from a *remote* location. Voltage must be applied to operate the shunt trip. In generator set applications the DC control power is often derived from the generator set starting batteries.

4.6.6.5.6 Motor Operators

Motor operators provide remote ON, OFF/RESET control for the circuit breaker.

4.6.6.5.7 Handle Padlock Attachment

Padlocks allow breakers to be locked in the open position to prevent downstream circuits from becoming energized. They are used to satisfy lock-out/tag-out requirements for maintenance

4.6.6.5.8 Handle Extensions

Handle extensions allow for operation of the breaker without opening the cabinet in which the breaker is installed, reducing the requirement for arc flash protection equipment.

4.6.6.5.9 Connection Provisions (mechanical and compression termination)

Breakers are most often supplied with mechanical lugs for connecting label. Proper system maintenance requires that torque on the lugs be checked annually. In some cases compression lugs are supplied. Compression lugs have the advantage that there is less risk of the connection coming loose so annual inspections are not required however compression lugs will require a crimping tool which is unique to manufacturer and model of lug to connect the cable.

4.7 Other Power Section Equipment

Power section equipment if often provided with many other features, depending on the needs of the installation:

- Fuses are used for protection of control wiring and other power carrying devices, when they do not incorporate internal protection. They may also be used to provide short circuit protection to a downstream system when limitation of the duration of fault current is necessary due to the rating of downstream devices.
- AC Metering provides a visual status of the characteristics and magnitude of power delivered to the system. A wide variety of metering devices are available, roughly broken into two types: traditional analog (needle and scale) and microprocessor-based digital metering. Analog displays are useful in that they provide an easy to understand means to quickly see the status of the system, and they make monitoring of transient conditions easier. Digital metering is more accurate, and can often be remotely monitored. Digital metering often can provide a full function metering feature at a similar cost to only a single function with analog metering.
- Control switches/status annunciation is provided to allow operator monitoring of the status of a system and to allow for manual control. There is a huge variety of equipment of this type available in the marketplace, and the designer’s primary concern is that the equipment is installed properly based on its ratings and duty cycle in the application. LED indicating lamps are preferred over incandescent, since they rarely fail over the life of a facility.
- Surge suppression/TVSS equipment is used to protect equipment from the effects of a voltage surge in the system. This equipment is critical in medium voltage systems and systems which are connected to the utility/mains systems, but is less critical in isolated bus systems.
- Lightning Protection is provided to protect systems from the effects of lightning on a system. The equipment is commonly specified in high-incident areas of the world, and in systems that are connected to the utility/mains by overhead conductors.
- Protective relaying is provided to protect the utility, generator sets, and load equipment from faults and to protect the generators and utility service from backfeed. Protective relaying is discussed in detail in **Chapter 6**.
- Neutral switching devices are provided to maintain proper neutral to ground connections as they are switched from the generator to the utility sources. Neutral switching is discussed in **Chapter 7**.

4.8 Paralleling Device Selection Recommendations

Paralleling circuit breaker selection considerations:

- Closing Speed and consistency: Since in many cases the phase relationship between the generator and the bus it is synchronizing to is constantly changing, accurate synchronizing demands use of a paralleling device that will close quickly (5 electrical cycles or less) and consistently.
- Operator Durability: Unlike most circuit breakers in a facility, a paralleling breaker is regularly opened and closed. So, it is important that it can operate reliably for the life of a facility in normal service. For standby applications, a good rule of thumb is to have the ability to operate 4000 cycles.

- Interrupting or Withstand Capacity: Circuit breakers have limitations as to the magnitude of current that can be safely carried or interrupted during a fault condition. In general, paralleling breakers should have withstand capability for 30 cycles so that they will stay closed long enough for downstream devices to clear before the generator set breaker opens.
- Serviceability: While many paralleling systems are normally de-energized because they are used for standby service, and repair of a paralleling breaker while the system is energized is not likely, some customers like the capability of being able to safely drawout the breaker of an energized system. As breakers get to the larger sizes (>1600 amps) they get larger and heavier, so drawout also makes them more convenient to manage for any necessary service, maintenance, or testing functions. If a breaker is normally energized, it should be a drawout device, so that a facility does not need to suffer a power interruption for service of the equipment.
- Neutral switching mechanisms

TABLE 15. CIRCUIT BREAKER REQUIREMENTS FOR PARALLELING

R=Recommended * = Required	**Manual**	**Exciter**	**Sequential**	**Random Access**
Overcurrent Protection	*	*	*	*
Interrupting rating equal to or greater than bus capacity	*	*	*	*
Steady State Rating equal or greater than individual generator rating	*	*	*	*
Electric Operator	R	R	*	*
5-Cycle Closing Capability			*	*
High Durability Operator			*	*
Drawout Design			*	*

4.9 Circuit Breaker Installations in Switchboards/Switchgear

Group mounted molded case breakers are the least expensive bus connected distribution option. Care should be taken to specify breakers which have sufficient interrupting capacity to be safely used on the system bus. Molded case breakers are not particularly suitable as load adding or load shedding devices, because their manual operators are not normally designed for switching duty operations. However, if they are used for this purpose (for example, in a retrofit application where transfer switches cannot be used for load adding/shedding), they can be factory wired for required functions.

Individually mounted molded case breakers provide physical separation and isolation for each distribution device for added protection in the event of a catastrophic failure of the switchgear.

Individually mounted power air or insulated case circuit breakers are available in either stationary or drawout configurations. Because of the relatively small physical size of insulated case breakers under 2000 amperes, and because the emergency system is normally not active, a designer may choose to limit system cost by specifying stationary mounting provisions for insulated case breakers. Due to their physical size and weight, power air circuit breakers are normally specified with drawout provisions.

Power air or insulated case breakers can be used with load transfer controls to provide a load transfer system without use of transfer switches. This can reduce system cost, but may require special consideration of the ground fault system, because these devices are not universally available with 4--pole switching mechanisms.

Neutral switching can also be accomplished by use of neutral contactors or breakers. See Chapter 7 on page 203 for more information on this equipment and its application.

4.10 Medium Voltage Equipment

The figure below is an illustration of a typical medium voltage standby utility paralleling/load transfer system with utility paralleling capability.

Medium voltage paralleling systems are often schematically similar to low voltage systems that do not use automatic transfer switches. These systems use substantially identical control components and have similar operating sequences.

A discussion on the reasons for using medium voltage versus low voltage equipment can be found in Chapter 5 on page 105.

FIGURE 47. MEDIUM VOLTAGE PARALLELING SYSTEM WITH MASTER CONTROL.

Medium voltage switchgear is typically larger and requires more access area than low voltage equipment. Because the entire switchgear structure is dedicated to the breakers and control power and metering potential transformers, the controls are often completely isolated from the power switchgear. Medium voltage “transfer switches" with specially designed contactors are not available. ATS functions are typically performed with vacuum breakers or contactors. (Careful review of device used is necessary to achieve expected life in the application.) See Chapter 5 on page 105 for more information on the decision to use medium versus low voltage equipment.

Medium voltage breakers are not available in as many frame sizes as low voltage breakers. In the U.S., common sizes are 1200 and 2000 amps. In IEC markets, 600 amp breakers are also available. These breakers are considerably larger (in terms of steady state rating) than the generator set they are switching to the bus. This raises the cost per kW of the system and space required for the system, but has no other negative impact. Note that in the figure above, the breaker sections all only have one circuit breaker per section. This is due to spacing requirements for high voltage equipment and necessary potential (voltage) transformers that take space in the sections, or simply the construction available from the supplier. There are typically not more than two breakers in a medium voltage switchgear lineup.

Another difference between low voltage and medium voltage systems is that the circuit breakers available at medium voltage are often not supplied with integral trip units. For this reason, the designer has the added task of choosing appropriate protective relaying for the system.

Control power for electrical operation of medium voltage breakers may be either AC or DC, as in low voltage systems. However, in medium voltage systems the power level demanded for switching and the costs of providing that power often lead to different decisions on control power arrangements. In low voltage systems the paralleling breaker is usually closed with AC power from the generator set it is connected to. This leads to a reliable system because each generator set is an independent system, capable of connecting to the bus whether or not other equipment is connected or available. In medium voltage systems, this may not be done due to costs of providing necessary transformers and protection for the low voltage power to operate the breakers. When this is an issue, DC battery racks can be provided. The size of the battery rack is dependent on the number of operating breakers and their duty cycles.

Medium voltage breakers are commonly provided with contacts that are encased in a vacuum container or a container filled with sulfur hexafluoride gas (SF6). SF6 gas is a colorless, odorless, inert gas that has excellent arc quenching, insulating, and cooling properties that prevent an arc from being maintained between the contacts in the medium voltage breaker. Similarly, devices that utilize a vacuum enclosure for the contacts prevent an arc from being maintained. Early vacuum and SF6 had various negative characteristics which competitors quickly pounced on, but current generation equipment has been proven to provide years of reliable service. It is recommended that the viability of the vacuum or SF6 container be monitored so that any failure in containment can be quickly repaired.

4.10.1 Medium Voltage Protection Relaying

Since medium voltage breakers often do not include integral protective devices, the protection can be selected based on the needs of the application. General considerations for the protection of generator sets and conductors to paralleling breakers are covered in **Chapter 7 on page 203**. Protection for switchgear and downstream devices is done in a similar fashion as in normal distribution systems, so it is not covered in this manual.

4.11 Switchboard/Switchgear Manufacturing, Testing, Installation

Switchboard/switchgear equipment is factory assembled equipment, usually customized with specific features for a specific application.

4.11.1 Factory Testing

Testing of paralleling switchgear is very similar to testing of any other switchgear line-up. On completion of the final assembly process, the equipment is commonly tested for proper assembly using processes described **Section 4.11.4 on page 102**. The equipment is tested to verify that the breakers open and close on command, and that other installed components are operating properly. Ideally, the equipment is operationally tested with the controls and associated equipment from the generator set supplier so that problems in the installation at the site are avoided. The sequence of operation of the system should also be fully vetted at the factory, including tests for misoperating components such as auxiliary contacts that fail to operate correctly. System proposals should include a detailed factory test plan to validate system operation.

4.11.2 Handling and Storage

In most cases the switchboard/switchgear assemblies for a paralleling project will be large enough that they will be shipped in several sections, with each section shipped upright on skids or a pallet. Switchboards should not be shipped or moved on their side or back unless they are specifically labeled to indicate that is acceptable. Note that switchboards are not necessarily designed to be moved in a specific way. Some are designed to be moved only by picking them up from the bottom, others have means included to allow lifting them in place from the top. Specific rigging and handling instructions must be carefully followed to avoid damage to the equipment.

When a switchboard arrives at a project site, it is important that it be unpacked and checked for physical damage, so that it can be repaired as quickly as possible without impacting on the project schedule.

In general, equipment is not designed to be stored out-of-doors, and should be kept in a dry, clean, air conditioned space, and protected from physical damage including dust and moisture.

Because of the large physical size of each section of equipment and the limitations in how it is moved, it is important to plan the process of moving the equipment early and carefully to be sure that the equipment can be transported to the installation location.

4.11.3 Installation Design Consideration

Switchgear is usually large and requires specific clearances around the equipment for safe operation as required for compliance to local and regional codes. These clearances will change depending on site conditions and voltage class of the equipment. The equipment designs of various manufacturers can vary significantly in terms of space requirements, and some variation in location of devices can often result in optimizing space required.

Also consider that since the equipment is large, the path and process of moving the equipment into place will need early planning.

Ventilation requirements – Switchboards/switchgear can produce significant amounts of heat, so it is important that equipment vents are not blocked or impeded and the heat be allowed to dissipate from inside the enclosure, and proper ventilation is provided for the switchgear room. If the switchgear lineup is in a small building with limited ventilation, an air conditioner may need to be added. Care should be taken to cool only to a level that will not produce condensation in the equipment.

Ambient temperature requirements – Equipment designed to ANSI and IEC standards is designed to operate at a nominal 40 °C ambient and equipment may need to be derated if equipment is operated in higher ambient temperatures. See Section 4.5.5 on page 75 for specific recommendations.

Dry clean air – Switchboard/switchgear equipment is particularly sensitive to humidity, condensation and dust. This is particularly true in medium voltage applications, where a problem with partial discharge or short circuit from live bus to ground can occur if enough humidity or dust is present, or voltage may actually track and find its way to the nearest grounded part causing an arcing ground fault. Using a heater and thermostat may be necessary in high humidity areas, and with normally de-energized equipment.

Floor drains – The site should have a means of draining standing water, and in most cases the switchgear should be set on a 3”– 4” housekeeping pad (plinth), this allows cleaning of the floor around equipment while protecting equipment from liquid and dirt. Some equipment designs, particularly those using large drawout breakers may not allow use of a housekeeping pad.

Piping of liquids and steam above or around switchgear should be avoided. Sprinkler systems for fire protection within switch rooms may require the switchboard/switchgear be designed for higher levels of water ingress protection. Note that planning for the fire protection equipment and switchgear location must be coordinated to assure that proper enclosures are provided for the installed equipment location.

Lighting/convenience receptacles – It may desired to include convenience receptacles for local power or lighting, especially if the Switchgear is located in an outdoor stand-alone enclosure away from the main building. This may be accomplished by adding a control power transformer or potential transformer to the switchgear lineup. Some codes and standards require emergency lighting around generation equipment (including paralleling gear) which is operated off DC or generator power.

Seismic versus Typical Installation – Depending on the location of the site, it will be required that the Switchgear be built and installed to meet local building codes. Many locations in North America follow the International Building Code (IBC). The IBC and other codes have guidelines that must be followed as to the size and location of the anchors that hold the switchgear in place depending on the weight and moments of inertia.

4.11.3.1 Equipment Installation Considerations

Equipment must be installed per the manufacturer’s requirements, and in compliance to application local, national, or regional codes and standards.

4.11.4 Start Up and Commissioning of Switchboards/Switchgear

The general process of commissioning and start-up of an isolated bus paralleling switchboard/switchgear system will require attention to the following steps:

- The de-energized equipment is thoroughly cleaned prior to the start of the process.
- All field connections including bus connections and field conductors are checked for proper torque.
- Typical testing is accomplished including: megger or high pot test (as applicable), phasing, validation of control and power connections, relay testing, etc.
- Each generator set is installed and proper operation is verified as a single generator set. The paralleling breaker is verified to open and close manually using the paralleling control system.

- The phase relationship of each generator set to the balance of the system, and to each other.
- A generator is closed to the bus, and a second generator set is manually paralleled to the bus so that load sharing can be verified. Each generator set is manually paralleled and load sharing adjusted.
- Automatic operation of the system is verified.

Commissioning processes often involve operation of energized equipment. Appropriate protective equipment for personnel operating on energized equipment must be used.

Refer to **Section 8.3.2 on page 245** for more information on this subject.

See **Chapter 6 on page 169** for information on typical settings for system protective devices for generator and generator paralleling breaker.

4.12 Maintenance of Switchboards/Switchgear

Equipment must be maintained per the manufacturer's specifications and requirements. Paralleling systems require testing and exercise using the generator sets and power transfer equipment (when used) in order to verify proper operation and provide for proper maintenance.

Equipment is generally required to be maintained at least once per year and after any condition that causes a breaker trip due to a fault in the downstream equipment. Regular thermographic analysis may also indicate a need for maintenance. Annual maintenance typically includes:

- Cleaning the equipment to remove dust and dirt from the inside and outside of the equipment.
- Verifying torque specifications on all fasteners in the equipment
- Exercising each breaker (either or electrically or mechanically opening and reclosing it)

The equipment must be de-energized for this work to be completed.

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5 On-Site Power System - Design Considerations

5.1 Overview

This section describes system design considerations, including descriptions of common one-line electrical designs, sequences of operation, and advantages and disadvantages of various designs based on application requirements. The purpose of this section is to describe how paralleling equipment and generator sets can be integrated into a site application, typical uses for various topologies and how these different designs may be optimized.

5.2 Requirements and Recommendations

5.2.1 Requirements

- Each generator set in a paralleling system used for emergency standby applications should be able to pick up all the loads required to be served within 10 seconds in one step.
- Emergency/standby power systems need the ability to shed loads when their power source is derived from multiple generator sets, in order to retain the ability to service the most critical loads if a generator set failure or overload occurs.
- The paralleling switchgear or switchboard used to connect the generators in a paralleling system together must be selected to safely carry both the maximum steady state load possible at any point on the bus, and also to withstand the forces induced in the system on any short circuit condition.
- All equipment and devices used in paralleling applications must be applied within their ratings for ambient conditions.

5.2.2 Recommendations

- It is desirable to operate the generator sets in a paralleling system at the same voltage as the most critical loads to be served.
- The most reliable systems generally have smallest numbers of generator sets to serve the loads, as long as necessary redundancy is in place.
- In any unattended emergency/standby paralleling system, the first priority load block should not exceed the capacity of any single system generator set.

5.3 General System Considerations

5.3.1 System Voltage

The control equipment required for a paralleling system does not change significantly with changes in voltage, but there are many ramifications to the system cost and design.

There are three voltage “classes” that are commonly used for on-site generation equipment in North America. There is not a uniform terminology for these classes around the world, but within this manual the following terms are used:

- 600 volt and lower (“low voltage”, or “line voltage”);
- 1,000-5,000 volt (“medium voltage”) 5 kV class equipment;
- >5,000 volt (“medium voltage”), 15 kV class equipment used at various voltages up to 13,800 VAC. Voltage levels up to 35 kV are termed “medium voltage”, but these higher voltages are not commonly used in on-site power systems.
- Because alternator designs vary significantly across the MV range, Cummins Power Generation alternators operating at up to 4160 VAC (L-L) are termed “medium voltage” and over 6000 VAC (L-L) are termed “high voltage”.

In general, the cost of switchgear equipment on a “cost per amp” basis increases as the voltage increases through the voltage “classes”, but the highest voltage within a class is the least expensive in that class, because operating current levels are lowest for a specific kW rating. Installation cost for the various systems varies considerably with specifics of the application but reduction in installation cost can be a good reason for moving up in voltage level. In general, as system loads and power generation capacity increases, there will be a practical limit of power production at any given voltage level and higher voltage equipment will be more expensive. It is also worth noting that medium voltage equipment requires different skill sets for installation and maintenance, which are less commonly available.

For emergency systems, it is desirable to operate the generator sets in a paralleling system at the same voltage as the emergency loads. This results in less equipment being installed between the generator set (or sets) and the loads, and improves the probability that the loads will be served when a power failure occurs. Local and regional codes may require use of special construction techniques and specific equipment approvals or listings for emergency applications.

The exception to this might be found in situations where capacity of the system is high, and it is not practical to locate the generator sets close to the loads that they serve. Another exception to the rule would be found in cases where the emergency system available fault current exceeds 100,000 amps at low voltage or system bus size is required to be higher than approximately 6000 amps. In that situation the added cost of the additional bracing needed in the switchgear and the more expensive breakers required might justify operating the generator sets at a higher voltage and transforming down to loads. The alternative to operating at higher voltage is to split the system into several sub-sections, and arrange the critical loads to be served from multiple sources.

Transfer switches may be installed into paralleling equipment structures to minimize installation costs and potentially improve connection reliability but this does significantly increase the cost of the transfer switch and the physical size of the switchboard. In some countries this practice would not be allowed due to local codes and standards. The largest transfer switches that are commercially available for low voltage applications are sized at 4000 amps (North American UL Listed transfer switches), so for emergency systems this is typically the largest loads that are applied to the system, and careful design of the system bus can often limit the bus ampacity to that level. Breaker pairs up to 5000 amps (6300 amps in IEC markets) can also provide transfer switch functions. For higher load levels/bracing levels medium voltage transfer systems can be provided.

5.3.2 Electrical System Design

When utility paralleling is not included in the system design, the generator set powered portion of the distribution system often has considerably different equipment rating requirements than the utility side of the system, which can safely and reliably allow use of lower cost equipment.

When utility paralleling is involved, the entire system can be exposed to combined fault levels equal to the sum of the utility and generator set fault current levels, so equipment rated for the higher available fault current must be used for equipment selection.

It is good practice (and required by code in some areas) to both electrically and mechanically separate the emergency loads from other loads in the system. This makes it considerably less likely that failures in non-critical circuits will impact on operation of critical loads. Note also that some codes and standards, particularly in North America, require isolation of control wiring and power wiring between the most critical loads and less critical equipment. Critical load circuits (control and power) also commonly require additional protection against fire in the facility impacting on availability.

Care should be taken to be sure that not only is equipment protected from the effects of short circuits and overloads, but that all equipment is properly coordinated to isolate faults as close as possible to the faulted point in the circuit. When the generator set is operated isolated from the utility grid, there can be difficulties in providing adequate fault current for effective coordination.

5.3.3 Power Switching Equipment Considerations

In low voltage systems, the best reliability is often achieved with transfer switches located physically closest to the loads that they serve. So, it is not uncommon to have ATS equipment located at considerable distance from the generator set, and in several places around a facility. ATS and generator set equipment with digital controls can utilize network-based communication to allow users to monitor the entire installed system at any point in the system. (The ATS equipment displays status of all ATS and generator set status information, the generator set can display all ATS data, etc.) This practice greatly aids operating personnel by providing critical information on the state of the equipment, particularly under emergency conditions.

In situations where switching is done at high current levels close to the service entrance or those systems operating at medium voltage, switching can be done using circuit breakers at lower cost than using transfer switches. Care should be taken to select equipment with durability appropriate to the operating life required for the application. It is also important to recognize that some applications are required by code (in North America) to used listed transfer switches.

Distribution equipment often can incorporate group-mounted protective devices (panelboard) construction, to minimize space requirements and equipment cost. This is acceptable because the circuits fed are at the “bottom” (final or branch circuit level) of the facility distribution circuit, minimizing need for a high degree of flexibility for coordination, and because the breakers are normally closed/manually operated when fed by both the normal and emergency/standby power sources. Again, some codes and standards (USA) require isolation between protective devices that may prevent the use of a panelboard construction or use of multiple panelboards for a system.

5.3.4 Generator Set Size and Quantity

When determining the number and size of the generator sets for an emergency/standby system, the following factors should be considered:

Minimize the number of generator sets (smaller number of larger generator sets), but use a sufficient number of generator sets to provide the level of reliability required for the application. Selection is based on the worst case load assumption and capacity that is needed to provide needed transient performance, as it is in a single generator set application. PC-based tools, such as Cummins Power Generation GenSize™ can be used to model system loads and determine the appropriate generator system size for a specific application.

Determine the size of the first priority load (or loads). Select generator sets of a kW rating sufficient for one generator set to start and operate all the first priority loads. For emergency/standby applications select generator sets that all have the same kW rating. This allows the system to carry the maximum amount of first priority load.

With the total system size established, and the total required capacity for first priority loads, the number and size of generator sets can be selected, with the smallest generator in the system able to pick up all the first priority loads. The number and actual size of the generator sets used is a critical decision, because while the cost per kW for the system generally goes up as the number of generator sets in the system goes up, the costs for generator sets of a specific rating may be sufficient to arrive at the lowest overall system cost. For example, four 1000 kW machines paralleled may be less expensive than a system with two 2000 kW machines. The lowest cost overall cost system may be different for each manufacturer.

If all loads are considered to be first priority, then load shedding may not be practical. In this case, redundant generator set (or sets) are necessary to protect against the loss of any single generator set in order to retain system reliability. As the number of generator sets on the bus increases the probability of more than one generator set failing at one time increases. Statistically, the number of redundant generator sets needed on a system bus depends on the number of generator sets on the bus and the expected reliability of the generator sets. So, with typical levels of generator set reliability it can be expected that one redundant machine is sufficient for up to 6 generator sets, but another redundant machine may be desired for larger numbers of generator sets.

Consider that even though it may not be desirable to shed loads, it would be better to do so than to lose the whole system. One practice that is helpful is to group loads in operational groups rather than based on type of load. For example, in a data center system, all the loads required to operate a portion of the facility (cooling, ventilation, lighting, UPS, etc.) could be grouped together so that while the system would lose capacity on loss of a generator set, it would still be operational at some level.

If generator sets of dissimilar size are used in an emergency/standby system, care must be taken in the design of the system sequence of operation so that the largest generator set (or sets) in the system are first to close to the bus; or, the first load step applied to the bus is always within the capacity of the smallest generator set in the system.

For prime power systems the number and size of the generator sets might be dictated by the size that allows optimization of fuel consumption or other life cycle cost considerations.

5.4 Load Control Systems

5.4.1 Load Division

Each generator set in a paralleling system can supply only a portion of the total system load. The system capacity increases and decreases as generator sets close to the bus and disconnect from the bus. The loads therefore must be divided and prioritized to prevent overloading of the system bus on black start operation or on failure of a generator set. The most critical loads should be added to the bus as soon as the first generator (in a random access system) comes on line with other loads added as more capacity becomes available. Section 5.10.2 provides information on typical sequences of operation for various topologies.

Loads are generally broken into groups based on the priority of the loads served, the physical location of the loads, and in some cases the characteristics of loads. Codes and standards often dictate the load-adding sequence by defining which facility loads must be serviced first, and usually a minimum time in which they must be served. In most cases, for emergency systems requiring all first priority loads to be served within 10 seconds of a power failure, the first generator set available must pick up all the first priority loads, because synchronization of multiple generator sets using random access paralleling control systems cannot be reliably achieved in a 10-second window. (U.S. code requirement for emergency systems.) However, in sites where service to the first block of loads can be delayed by 15 or 20 seconds, multiple machines may be available and ready to service larger load steps.

5.4.2 Load Size, Quantity, and Priority Levels

The size and number of load blocks has a bearing on the size and number of generator sets in the system. Systems can be designed to serve load blocks of varied sizes, including individual load blocks that exceed the capacity of a single generator set. Systems can be designed to match the number and size of the load blocks to the number and size of the generator sets.

In any unattended emergency/standby paralleling system, the first priority load block should not exceed the capacity of any single system generator set.

After the number and size of the load blocks has been determined, the load blocks must be assigned priority levels. The number of priority levels will usually match the number of generator sets. Selection of load block size, quantity, and priority establishes the sequence for adding the various loads to the bus as generator sets come on line. This is called priority pickup. The function of dropping lower priority loads off the bus in the event of an overload is called load shed. The pickup and load shed priorities may not necessarily be the same. In North America the U.S. National Electrical Code specifies the priority level of some loads.

5.4.3 Priority Pickup (Load Add Sequencing)

Priority pickup is the function of a paralleling system to add load blocks to the system bus in response to the system generator sets coming on line. The priority pickup controls prevent overloading the system bus by inhibiting transfer of selected loads until additional sets are closed to the bus.

In a system with three generator sets, for example, three levels of pickup priority (load step levels) would typically be established (more than one load can be in each of these levels). Each load block would be sized to match the capacity of a single set. After the first set is connected to the bus, the highest (most critical) priority load would be added to the bus. After the second set is connected to the bus, the priority two loads would be added. After the third set is subsequently connected to the bus, the priority three loads would be added.

In another system with three generator sets, two levels of priority could be established. In this system, a first priority load block would be sized to match the kW capacity of any one of the three generator sets. A second priority load block may be sized larger than the capacity of a single generator set, but within the capacity of any two. After the first generator set is connected to the bus, the highest (most critical) priority load would be added to the bus. After the second and the third generator sets are connected to the bus, the priority two load block would be added.

5.4.4 Load Shed

A paralleling system must be designed to respond to a bus overload condition in order to prevent total system failure. Load shed is the function of a paralleling system to disconnect load blocks from the system bus in response to bus overload. The purpose of load shed is (in the event of generator set failure or bus overload) to serve the higher priority loads with power from the remaining on-line generator sets.

If a failure of a generator set causes a bus overload (based on sustained under frequency, kW magnitude, or both), a load shed signal initiates load shedding in the system, beginning with the lowest priority loads. If the bus does not return to proper frequency within a predetermined period of time, additional load shed signals are generated and additional load blocks are dropped from the bus. Power is provided to the higher priority loads without interruption. To limit the amount of load that is shed in response to an overload-to keep as much equipment as possible on line-load can be shed in blocks that are smaller than the priority pickup load blocks.

One variation on the load shed sequence described above is the use of load modulation (also known as “bus optimization”) rather than load shedding to manage load on the bus. (Much like a peak shaving system might do to minimize peak demand by managing loads.) In these systems the system designer designates the magnitude of specific lower-priority load steps or the system continuously monitors the load step magnitude. On system starting, the controls add load in sequence until the system has reached operating capacity. After that point, the system monitors total load level, and turns specific loads (usually non-critical loads) on and off in sequence to maintain partial service to these loads, rather than providing no service at all during a power failure condition. Load modulation systems are normally backed up by an emergency load shed system that will dump a large block of loads if there is a sustained bus under frequency condition. Load modulation systems are complex and require identification of a large number of switching points, so many customers prefer use of facility management systems for implementing this type of operation rather than using the paralleling system. This is particularly true when a facility uses load management equipment when on normal power.

Some load shedding systems incorporate an “emergency load dump” to respond to a sustained under frequency condition with a large, fast load dropping function. These systems are particularly useful in situations where the load adding and shedding system modulates loads as noted above.

5.4.5 Devices and System Equipment for Load Control

In general, maintaining the integrity of the generator bus if there is a loss of capacity will involve either adding capacity (if there is a redundant generator set), or causing the load level to be dropped by some other means. Arguably all systems, even prime power systems that serve dispersed loads around a community, will all require some level of load shedding to prevent total loss of a system on a generator failure. The only exception might be in systems operating with enough excess capacity to make this unnecessary. But in general, load control is a necessary function in the system. It is not possible for a supplier to predict how many levels of load control will be necessary for a system, so it is critical that the system designer identifies the load steps and sizes for the specific design provided. Several mechanisms may be potentially used to perform the required tasks. More than one type can be used in a system with no reduction in system reliability. A discussion of load management alternatives follows. See Section 5.10.1.4 on page 131 for more information on load management system alternatives.

5.4.5.1 Transfer Switches

Transfer switches built with dedicated purpose contactors, when they are used in a distribution system, are an ideal mechanism because they are specifically designed to switch loads on and off and between energized sources, and can accomplish this over many thousands of cycles without an impact on reliability. Many dedicated purpose transfer switches also are able to disconnect from both sources, which is desirable because the need to disconnect from the generator bus may come at a time when connection to the primary source is undesirable, such as when the primary source is operating single-phased.

The physical interconnection means for a system to communicate start commands and load adding and shedding commands may be either discrete signals or via network communications. Network systems are generally less expensive and more flexible than hard-wired systems. The network can also be redundant for better system reliability.

5.4.5.2 Feeder Breakers

Electrically operated feeder breakers can be used for load management. In the event this is done, the breaker should be selected with an understanding that it may be required to operate hundreds of time during the life of a facility. Thus breakers for use in this application are generally power circuit breakers or insulated case circuit breakers. Molded case breakers may be used if the supplier has demonstrated via prototype testing that they can reliably survive approximately 2000 electrically operated cycles under load.

Feeder breakers are commonly operated using discrete signals, and are often installing in a single switchboard with the paralleling devices.

5.4.5.3 Building Management Systems

With the advent of facility-wide energy management and control systems, it has become possible for a paralleling power system to be integrated with a facility management system to allow the management system to control load level during generator bus operation. The overwhelming advantage of this choice is that since the devices are controlled anyway, nearly no incremental cost is incurred to use the same devices for load management during generator operation. This often allows the entire facility power system to be monitored using the same system.

Communication between systems may be achieved by a simple discrete signal from the generator system indicating that it is operating the facility, or may be done via a network arrangement allowing data from the entire system to be monitored.

5.5 Capacity Control Systems (Load Demand)

Systems that are used for prime power applications and other systems that are intended for operation for extended periods of time may incorporate a Load Demand (also called “generator optimization”) function. Load Demand is a function provided by the system that will monitor the total load on the system bus, and turn generator sets on and off to maintain a minimum load on the generator sets, while assuring that there is adequate capacity for system loads.

The key benefit of a load demand system is that it reduces fuel consumption by the generator sets when they are running. There is some risk in its use; however, since a sudden load change with some generator sets shut down can cause what might be interpreted as a nuisance load shed or bus voltage and frequency disturbance. Also, with reserve capacity already on line, an unexpected failure of a single generator set will be less likely to cause load shedding or serious disturbances in power quality. The settings of the load demand system require a clear understanding of the size of load changes that can occur in the system, balanced against the capacity of the generator sets in the system.

Load demand systems typically are provided with an initial time delay that is intended to prevent shutting down of generator sets until the load on the system is stabilized (for example, after a power failure). This time delay is typically adjustable, and often would have a nominal value of approximately 15 minutes. The system designer should adjust this time delay with an understanding of how loads are applied after system initial starting. The load demand operation should not start until power is supplied to all loads, and the various system loads are stabilized in their operation.

Once the initial time delay has been completed, the system will monitor the total load on the bus. If the load is less than a preset kW level, it will signal one of the generator sets in the system to shut down. That generator set will generally ramp to a no load condition, open its paralleling breaker, operate for a cooldown period, and then shut down. Most load demand systems incorporate controls to allow an operator to select the sequence that machines will shut down on load demand conditions. Another alternative is to allow the system to make calculations to maintain near equal operating hours on each generator set, or in prime power systems, may be determined based on optimum fuel consumption rate for the site.

The system will continue to monitor the total load on the bus and may shut down other generator sets if their capacity is not needed by the system. Again, time delays are incorporated into the system to allow loads to stabilize after every control action.

If the loads on the system bus increase to above a system set point, the control system will signal one of the generator sets to start. It will then start, synchronize, close to the bus, and ramp up to share load with the generator sets on the bus.

If there is a bus overload, all the idle generator sets may be started, and loads may be shed to maintain power flow to the most critical loads in the system.

Load demand systems normally incorporate an ON/OFF switch to allow an operator to switch off the function and keep all generator sets in the system running during power failure conditions. The Load Demand function is often turned off in situations where the redundancy (and improved reliability) of the system is of greater importance than fuel consumption savings.

5.6 Grounding (Earthing)

Although it is beyond the scope of this document to provide a complete discourse on the grounding of on-site electrical power production and distribution systems, several points related to grounding should be considered in the design of on-site power systems that involve paralleling equipment. For a more complete discussion of grounding refer to IEEE Std 142-2007, the “Green Book". More information is also available in Chapter 7 on page 203, and Cummins Power Generation's T-011 and T-030 application manuals.

A number of factors can influence the designer's choice of grounding system, but in general, grounded systems offer distinct advantages over ungrounded systems in terms of power system voltage stability (lower probability of fault-induced voltage surges) and system operation safety, especially for paralleling applications for emergency/standby applications, since they are often operating at low voltage.

Ungrounded systems are rarely used in commercial and institutional facilities because of risks of potentially damaging voltage variation noted above. However, when powering process-controlled systems, the risks of overall system damage during a partial electrical system failure outweigh the risks. In these cases trained electricians are normally on duty to identify the location of ground faults and repair them before more serious problems can occur.

Solidly grounded systems provide the highest levels of line-to-ground fault current, so ground faults are more easily detected and in general are more quickly cleared than with other system designs. (Note that typical synchronous generators used in paralleling applications generate considerably higher fault current during line to ground faults than are experienced with Line to line to line and line to line faults.) They also are lower in cost than resistance grounded systems, and allow use of line-to-neutral connected loads. These are the most commonly selected grounding arrangement for emergency/standby power systems, especially in line voltage applications. Solidly grounded systems may be either 3-phase/3-wire or 3-phase/4-wire systems. In 3-phase/3-wire systems the neutral or any single phase may be grounded. (Grounded B phase with floating neutral is most common.)

Resistance grounded systems are designed to limit the magnitude of fault current that can flow in a line-to-ground fault, so they are sometimes considered to be safer than solidly grounded systems. (However, in general, emergency systems have such a low capacity relative to utility services that this is generally not true with on-site power systems.) Resistance grounded systems enable the sustaining of ground fault conditions in a load, rather than immediately tripping on sensing the condition. However, due to the lower levels of fault current available, the fault may be more difficult to sense, and coordination of the electrical system may be difficult. They cannot be used in distribution systems that use a neutral conductor, so their use is limited in scope, especially in low voltage applications. Resistance grounded systems are sometimes termed “low resistance” grounded or “high resistance” grounded.

Low resistance grounded systems are typically designed to allow 1½ to 2 times rated current to flow in a ground fault condition. They are usually limited to 10 seconds of operation. Often, low resistance grounded systems are used for MV and HV alternator protection, because they provide time to clear faults before alternator damage occurs, and they prevent overvoltage conditions that can damage both the alternator and potentially system loads. A useful alternative to use of low resistance grounding that allows more fault current availability for easier selective coordination is the use of excitation controls that regulate based on fault current rather than voltage.

High resistance grounded systems are typically used in process control applications, where it will be extremely expensive to shut down service to the load. They allow ground fault current to flow for extended periods of time, so that ground faults can be found and isolated without disturbing the loads.

Systems may also be grounded using reactors or transformers. Reactors are used in applications where it is desirable to limit quickly changing current levels. One application where they are sometimes used is in the interconnection of dissimilar alternators that are paralleled.

Regardless of the grounding method that is used, when a paralleling system is intended to operate for any period of time in parallel with the local utility service, the grounding system design decision should be made in consultation with the local service provider, as the grounding of the local system becomes a factor in the utility system design when the generator set, or sets, is paralleled to the grid.

See **Chapter 7 on page 203** for more detailed information on this subject.

5.7 Location and Environment

All equipment and devices used in paralleling applications must be applied within their ratings for ambient conditions. Some controls and applications require environmentally controlled environments. System designers should verify control environmental ratings and apply as recommended by the equipment or component suppliers.

Switchboard/switchgear equipment is generally designed for use in environmentally controlled locations. When temperature can vary over broad extremes, anti-condensation heaters should be specified to prevent damage to the equipment. In areas of high ambient temperatures, air-conditioning of switchgear rooms is desirable, especially when equipment is operating at a high load factor. In areas where the switchboard/switchgear will be operating at temperatures greater than 100 °F (40 °C) ventilation or even air conditioning should be applied; or, equipment de-rating factors will probably be required. (See **Chapter 4 on page 55** for more details.)

Paralleling breakers should be close to the generator sets that they are controlling. A good guideline is that the equipment should be within approximately 200 feet (60 meters) of the generator sets.

Technical limitations vary with equipment manufacturer, but generally a practical limit will be reached before the technical limit of the equipment. A major concern is the interface between the active control components of the system, such as the load sharing controls and governor controls. A good guideline is to keep the complex control interconnections short, with the more simple interconnections, such as interfaces with dry contacts; the distances can be greater with less risk of application problems. Where complex interconnections exist and distances are large, use of fiber optic interfaces can provide fast, effective interconnections.

In any event, the designer should recognize that different control and monitoring systems can have widely varying interconnection and wiring requirements, so special care should be taken to verify that the wiring materials installed are appropriate to meet equipment needs. In addition, special attention should be given to control grounding/earthing requirements for the control system, as various intermittent nuisance failures can occur due to incorrect installation in this area.

For ease of service, there should be direct physical access between the generator sets and paralleling equipment for technicians working on the system.

Care should be taken to locate the equipment in an area that is not likely to be flooded, and the equipment should be shielded from sprinkler equipment as it is normally provided in NEMA 1 (IP23) equipment enclosures.

Paralleling switchgear can be physically large, so access to the room for installation and working space requirements should be carefully considered. The equipment can generally be designed to be broken down to individual sections for installation, and the manufacturer's drawings should be consulted to verify the number and location of shipping breaks. The designer may need to specify the maximum size of the shipping sections that are supplied for a project, so that the equipment can be placed into the installation location.

Where multiple generators are installed in the same room, consideration shall be given to the various hazards encountered when maintaining a machine while others are able to start automatically or are in operation. For example: noise, rotating parts, hot surfaces and electrical hazards.

Local and national codes and standards govern space requirements around equipment. In general front, rear, and side access is needed for the power-carrying equipment that uses drawout circuit breakers. See the figures below for examples of recommended working space around equipment.

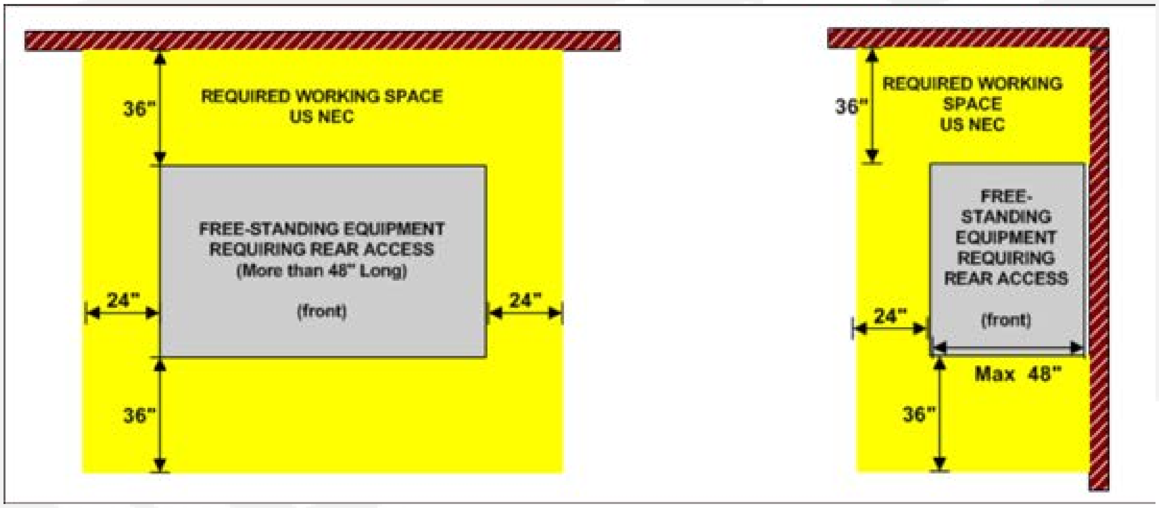

FIGURE 48. TYPICAL WORKING SPACE REQUIREMENTS AROUND FREE-STANDING SWITCHGEAR (LOW VOLTAGE).

FIGURE 49. TYPICAL WORKING SPACE REQUIREMENTS AROUND WALL-MOUNTED SWITCHGEAR (LOW VOLTAGE).

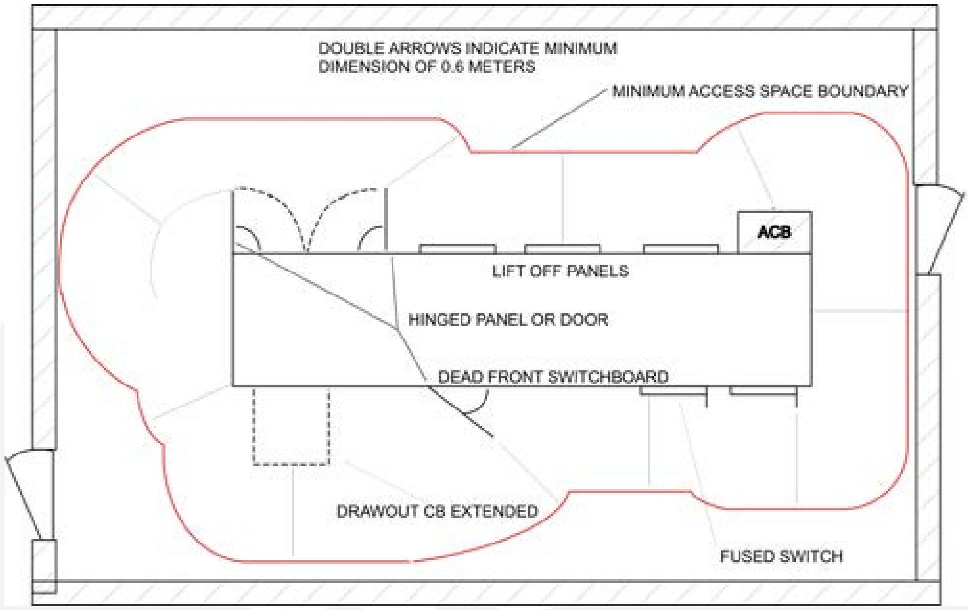

FIGURE 50. TYPICAL WORKING SPACE REQUIREMENTS UNDER IEC STANDARDS. FREESTANDING SWITCHBOARD WITH RACK-OUT SWITCHGEAR.

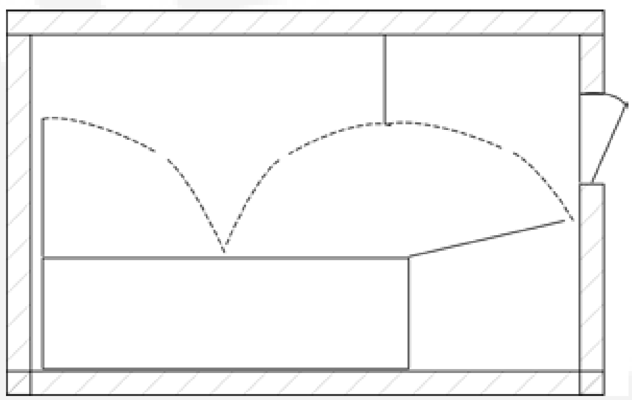

FIGURE 51. TYPICAL WORKING SPACE REQUIREMENTS UNDER IEC STANDARDS. SWITCHBOARD IN CORNER POSITION.

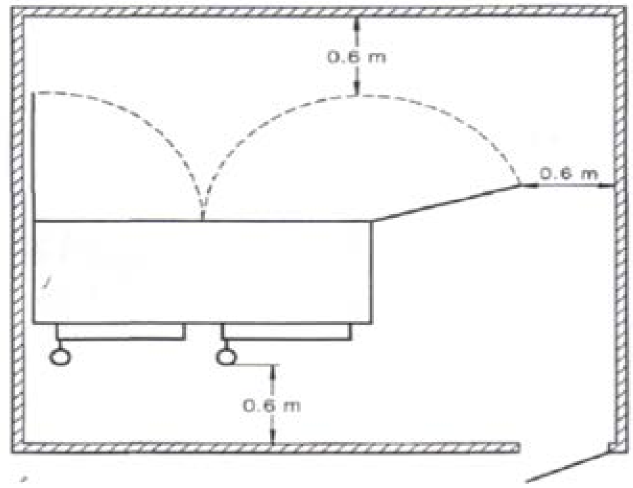

FIGURE 52. TYPICAL WORKING SPACE REQUIREMENTS UNDER IEC STANDARDS. SWITCHBOARD WITH ONE END AGAINST A WALL.

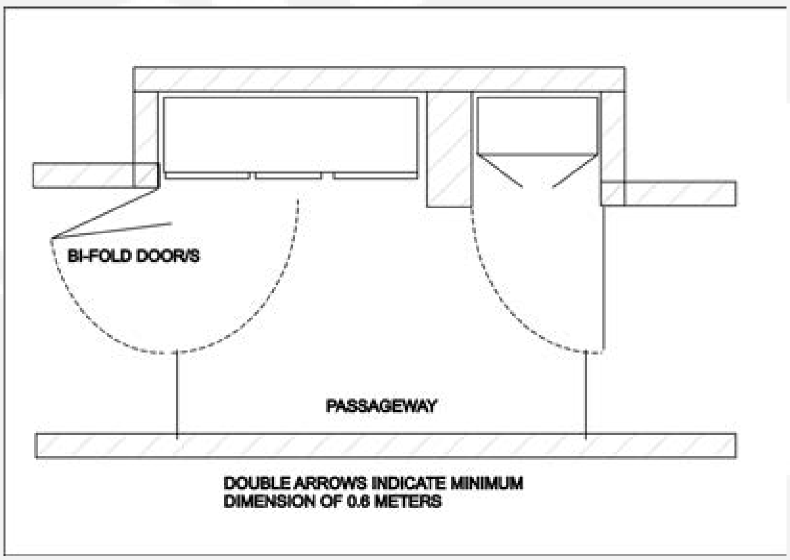

FIGURE 53. TYPICAL WORKING SPACE REQUIREMENTS UNDER IEC STANDARDS. SWITCHBOARDS WITH DOORS THAT OPEN INTO ACCESS-WAYS OR NARROW PASSAGEWAYS.

Note also that the generator sets are electrical equipment, so for practical maintenance and installation purposes, and because local authorities may demand compliance to working space requirements, access around the equipment is necessary. These rules are often applied only to space around the alternator, but can be imposed around the entire machine.

Mechanical considerations for generator sets in paralleling applications are covered in T-030, Generator Set Application manual. A critical factor to remember is that the generator sets will affect each other mechanically when they running, and system design should consider that. Where multiple generators are installed in a single room, the ventilation system must be evaluated based on the greatest number of generator sets that can operate at any time. A good guideline is that the design should allow all the machines to operate at full load, because even if a design does not intend that type of operation, as system loads increase, users may desire that capability.

When calculating the efficiency of an installation any parasitic loads such as ventilation equipment, pumps, lighting, and transformer efficiencies must be taken into account and may have an appreciable effect on the kW output available.

More information on switchboards/switchgear can be found in **Chapter 4 on page 55**.

5.8 Isolation of Paralleled Generator Sets

Generator sets are commonly required to have a means to electrically isolate them from the balance of a facility distribution system for two purposes:

- To allow a generator set to be safely serviced,
- To allow fire personnel to quickly and effectively remove power from a facility for the purpose of more safely fight a fire in the facility.

Most codes and standards have these requirements but the specific wording of code documents is usually directed toward single generator set facilities, not multiple generators in a paralleling application. This often requires some interpretation in order to assure that the installation design not only meets code requirements, but also provides the intended functions.

The figure below shows optional locations for required disconnects per U.S. NEC requirements. One disconnect is required for the utility/mains service entrance and a second for the generator set.

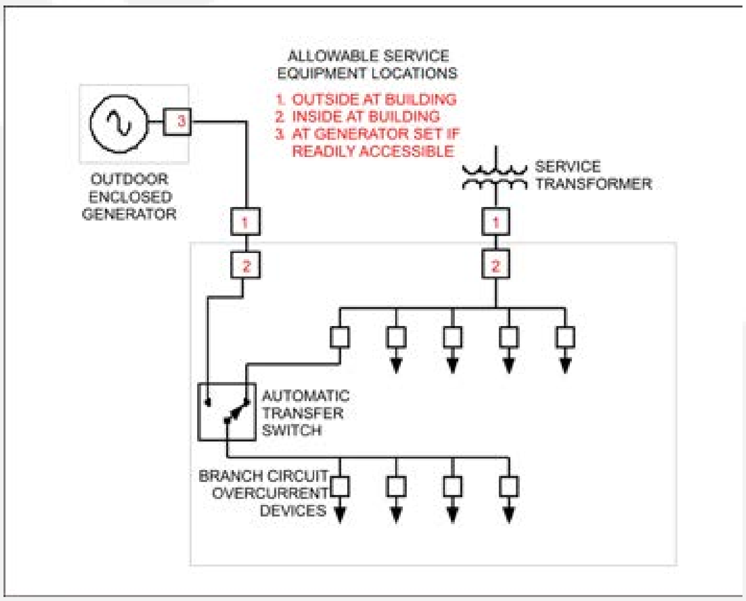

FIGURE 54. OPTIONAL LOCATIONS FOR REQUIRED DISCONNECTS.

It is worth noting that an isolation device such as a circuit breaker does not make a generator set safe to work on, because the generator set can still be remotely started such as by a transfer switch during a power failure.

With most isolation devices, there is no remote monitoring that the device is open, so if the device is not closed when service work is completed, there is often no remote notification of that condition. Consequently, a power failure might start the generator set, but it may stay disconnected from the load.

Finally, if there is an isolation means between a generator set and the paralleling breaker the system can misoperate if the isolation device is open but the paralleling breaker is closed. This can prevent the generator set from providing power to the load, and potentially result in total system failure, depending on several factors in the system control logic.

A proper installation design should address all these issues by providing a design that is safe for service of the generator set and provides a code-compliant means to shut down the generator system, notifies facility staff that the system is disabled when a disconnect is open, and opens the paralleling breaker if the associated disconnect is opened.

5.8.1 North American Applications

Isolation requirements in North American are often termed “disconnect rules”.

Generator sets that are paralleled are required by code to have an isolation device that opens the conductors from the generator set to the loads. It is prudent to include a lockable device that prevents an individual generator set from starting if it is being serviced. This device should allow multiple personnel to lock out the generator.

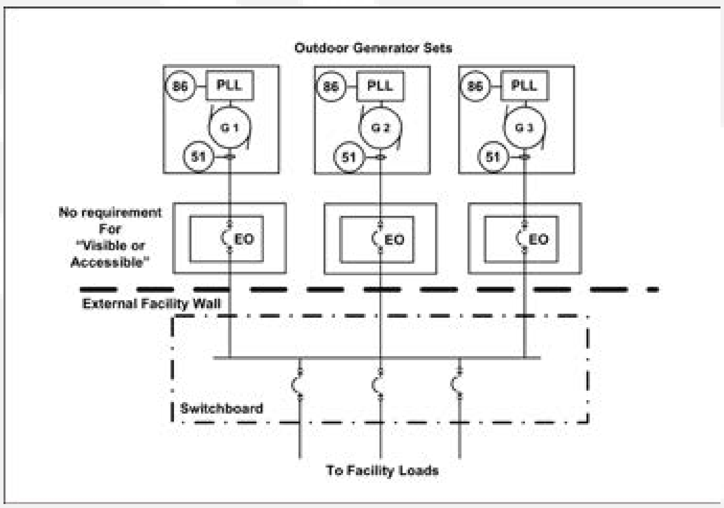

FIGURE 55. RECOMMENDED PRACTICE FOR COMPLIANCE TO ISOLATION REQUIREMENTS FOR OUTDOOR PARALLELED GENERATOR SETS.

NOTE: Listed in the figure above is overcurrent protection (protective relay) at the generator set terminals to protect the generator and conductors connected to it from both overload and short circuit conditions. An emergency stop switch with lock-out/tag-out provision increases safety of technicians working on the equipment.

Generator sets are also required to have a disconnect (isolation) device where the conductors from a generator set enter a building (if the generator is installed outdoors). The disconnect means may be either on the outside of the building or directly inside the building wall. This device may be mounted at the generator set if it is “visible and accessible”. Visible and Accessible generally means that the disconnect is visible at the wall of the building, within 25 feet, and the user can operate the device without climbing over barriers. (The specific site design is subject to interpretation compliance by the authority having jurisdiction.)

Finally, it is required that the distribution system be selectively coordinated. The complexity of this requirement is a result of the fact that commonly used disconnects for generator sets are molded case breakers with thermal-magnetic trips. If a device of this type is in a circuit with a paralleling breaker, which is commonly a power breaker with an electronic trip, not only will the disconnect not coordinate with the paralleling breaker (which in some cases is acceptable), but it will not generally coordinate with the balance of the distribution system. The coordination is difficult because it is not uncommon for a paralleling breaker to be smaller than some feeders on a parallel bus. Because all generators on a paralleling bus share all load (whether it is normal load, or load due to a fault condition) it is reasonable to factor this into the coordination/discrimination study, but not all authorities allow this, because they wish to see coordination through all the states of the system operation, including varying numbers of generator sets, loads, and loading conditions.

One way to meet these diverse and demanding requirements is to move to relay-based protection for the generator set, so that an instantaneous trip is not required and greater flexibility in curve shape is available. The above and below figures show two potential solutions for an application with outdoor generator sets and indoor switchboards/switchgear.

When both the paralleling equipment and generator sets are indoors the disconnect can generally be the paralleling breaker, and it need not be service entrance rated, so a configuration analogous to the figure above is commonly used.

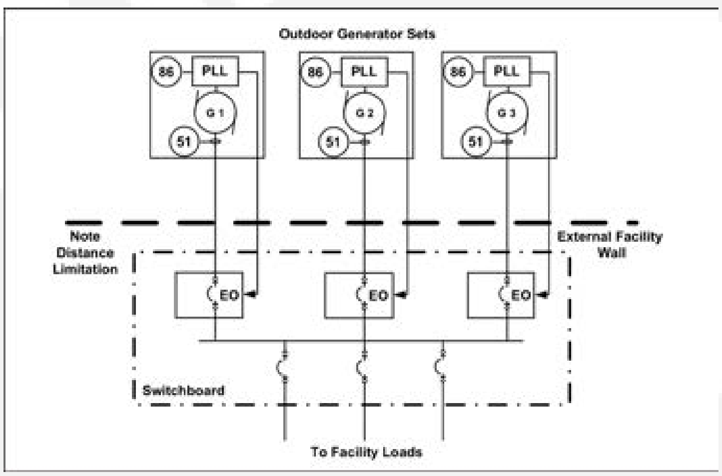

FIGURE 56. PARALLEL CB SECTIONS MUST MEET DISCONNECT REQUIREMENTS.

Note that the figure above shows distance limitation is the maximum distance between the facility wall and the switchboard/switchgear, which is usually specified by local codes.

5.8.2 Non-North American Applications

For countries outside of North America that utilize the IEC standards the intent of the standards remain the same as those in North America. The IEC standards require isolation of both the output of the alternator and the isolation of the generator set control system.

The isolation of the alternator can either be achieved by the use of an isolation switch or a circuit breaker, the isolation device can be mounted on or adjacent the alternator output terminals but must be fitted with lock-out/tag-out facilities. Please note that that the use of an isolation switch will still require the installation of overload and short circuit devices being installed to the output of the alternator.

The generator control system can be isolated in a number of ways. Typically this is achieved by the use of a lock-out/tag-out emergency push button mounted on the controller, or the installation of a lock-out/tag-out battery isolation switch on the engine starting batteries.

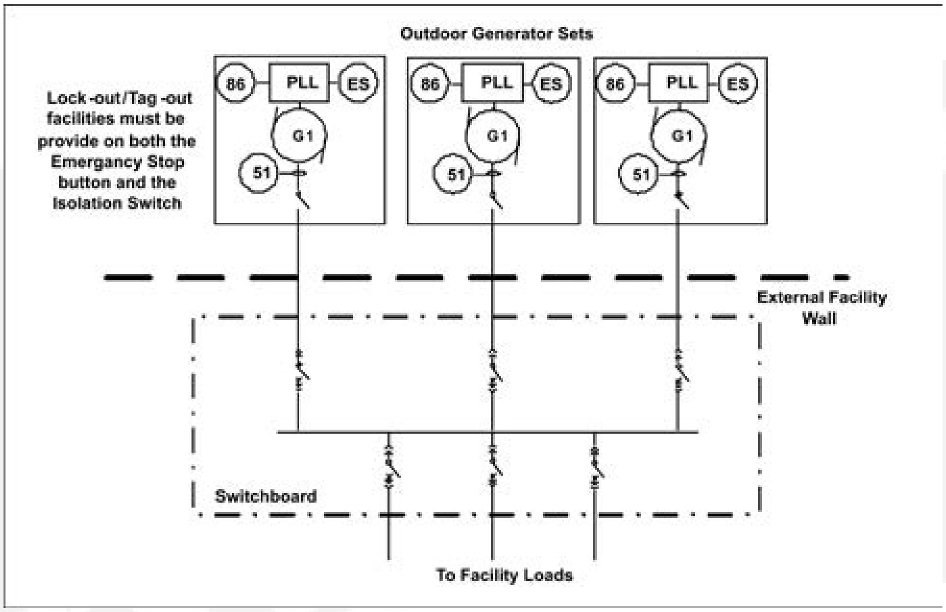

FIGURE 57. OUTDOOR IEC ISOLATION REQUIREMENTS.

Unlike North America, IEC standards do not have variations for generator sets installed within indoor or outdoor applications.

Fire codes and local fire requirements change from country to country and form area to area these codes and local requirements may require the installation of additional equipment to be compliant.

5.9 Remote Monitoring and Control of Paralleling Systems

Advances in the capability and availability of digital control systems have made it possible to produce fully automated paralleling systems that are capable of unattended operation at costs very similar to manually controlled systems of the past. The paralleling, generator set and load protection, and even the power transfer process can easily be accomplished without operator intervention.

This, along with continuing pressures in every business to reduce operating costs has resulted in the proliferation of remote monitoring systems that allow facility operators to be aware of system status and intervene where necessary, regardless of where they are in a facility—or even if they are not in the facility, in some cases.

There are a few local codes and standards that require remote annunciation of a generator set condition in manned locations, but in general, remote monitoring and control systems are an optional but potentially critical feature of power systems in a facility, especially in terms of reducing the cost and convenience of operating and maintaining the system over the life of the equipment.

In general, the system designer needs to ask a couple of simple questions in order to identify system requirements for remote monitoring and control:

- What do you want to have the operators able to do?
- Where do you want to have them to be able to do it?

Some common needs (in order of their importance) include:

- Advising operators or service personnel/systems of a failure or impending failure in the system or even the need for maintenance in the system. It is worth noting that each supplier of each piece of equipment will likely have slightly different types of alarm, status, and diagnostic messages available and will have only limited ability to change the overall information for a specific piece of equipment. There also can be a lot of information available. An emission-controlled generator set can have over 200 individual status, alarm, and diagnostic messages available.
- Allowing operators to monitor the condition or status of the system. This might include availability of sources, status of generator sets and ATS (running, not running, faults present, etc.), and status of fuel supply systems.
- Gathering data for diagnostics or system optimization. For example, the sources might be monitored for quality of power delivered to loads, and store data on system failures (such as short circuits) so that the root cause of events can be ascertained and appropriate corrective actions can be taken.

In many cases these systems cross over the equipment provided by multiple vendors in a single facility. For example, in a data center application the AC distribution system from the sources to the system loads includes equipment by switchboard/switchgear manufacturers, generator set and transfer system manufacturers, UPS system manufacturers and load equipment manufacturers of various types. If a load fails to operate, the data from any supplier in the chain may be critical in understanding the nature of a failure of the facility to deliver the needed service.

It also goes without saying that in most cases customers do not want a system from every supplier, but rather a single system that will serve all the customer's needs. This is critical in avoiding unnecessary duplicated costs, missing data, uncoordinated data (timing of events across the system), and simply the cost and effectiveness of training to allow the equipment to be effectively used.

The most common means to integrating multiple systems from various suppliers is to revert to a common interface for all the suppliers, and identify a single supplier to implement all the required monitoring and control. The most common interface currently used is Modbus® RTU. This is particularly effective in gathering data and viewing status in a system from multiple suppliers. In essence, this interface allows multiple suppliers to provide a data base (register map) of all the needed data, so that a central system can poll individual equipment and can display it all. Most suppliers can provide data in any form needed for a remote monitoring system, but speed of transmission and cost are limiting factors in the effectiveness of the approach offered when data conversions need to be made to make a system compatible with remote monitoring by a 3rd party.

It is also critical to identify how often specific data points need to be polled, as some data points change quickly and often, and other points may be static for weeks or even months. A strategy for data management is needed to be sure that needed data is available for diagnostics, but redundant data is not saved.

Network based remote monitoring control systems may be used for integration of the related control systems in a facility. Commonly done to reduce costs, a network interface can be used for interfaces of transfer switches to the paralleling equipment, for load sharing between generator sets, sequencing of loads in the system, and alarm/status annunciation.

Keep in mind that the facility life is likely to be very long relative to the “sales life” of system level equipment. For example, processor-based control equipment such as computers, PLCs, touchscreens, various types of dedicated purpose controllers, etc. commonly have an effective sales life (that is, time between each new model offered) of 3-5 years. After that time advances in processors and hardware capability commonly will result in manufacturers updating a product line and obsolescing older equipment. By contrast, the customer expectation of facility life may extend as long as 30 years or more.

As a result, it is necessary to consider how the installed systems within the facility can be supported through the life of the facility, especially considering the high degree of interconnection between the systems.

5.10 Electrical System Topology

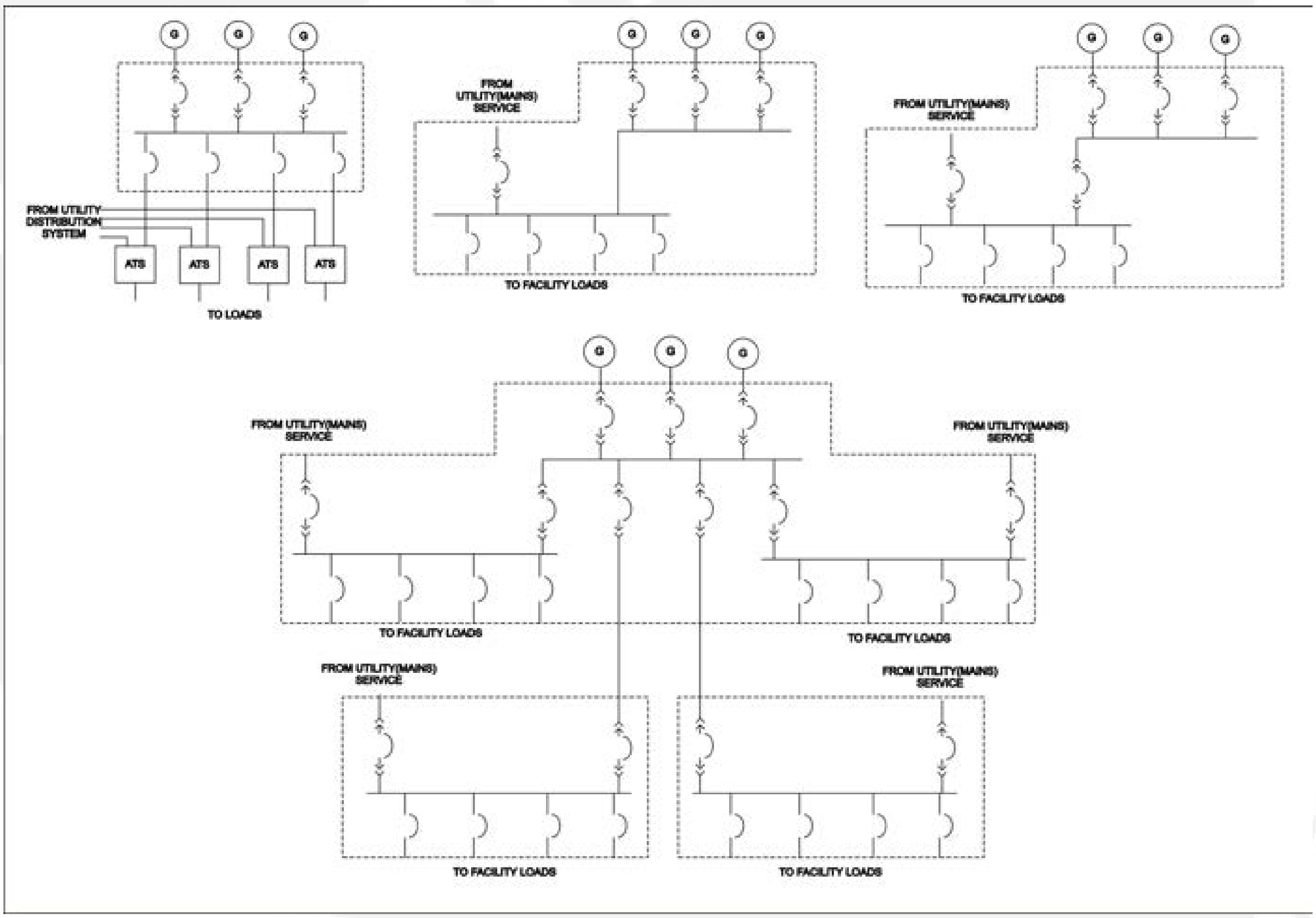

FIGURE 58. TYPICAL SYSTEM TOPOLOGIES FOUND IN GENERATOR SET PARALLELING APPLICATIONS.

Any good system design process includes careful consideration of the needs of the application and how they will impact on the system topology needed. The system topology is the general arrangement of the equipment providing power flow through the system, and other critical equipment directly connected to it.

While each facility is different, most facilities are served by one of several common topologies. (See figure above.) Understanding the advantages and disadvantages of each design and the variations that are commonly seen can help a designer make a more informed selection of system topology for a specific project. This section of material describes several common on-site power system designs that involve paralleling of generator sets to each other and in some cases to the utility service. For each system, a description of the system design, a list of advantages and disadvantages of the design and a sequence of operation are provided.

5.10.1 Sequence of Operation, In General

Before looking at typical system topologies, it will be useful to cover general considerations for sequences of operation.

While the various common systems have different operation sequences based on their overall topology, all the systems operate with following common “sub-sequences”. Following are brief explanations of typical sequences and common variations that are seen, and common failure modes and how they are addressed, all assuming a multiple generator set installation.

5.10.1.1 Generator Set Starting

A generator set can be given a signal to start via a simple contact closure over a network, from a remote control terminal that may be as simple as a control switch, or from a facility-wide SCADA system. More than one of these may be used jointly to improve the reliability of the starting signal. Best overall system reliability is achieved when the start signals go directly from the source of the signal (or signals) to the generator set controller. However, when there are a large number of transfer switches in a system, or they are a long distance from the genertaor sets, it may be more practical to do other designs to manage the system, as long as a single point of failure is not introduced into the system by nature of the design.

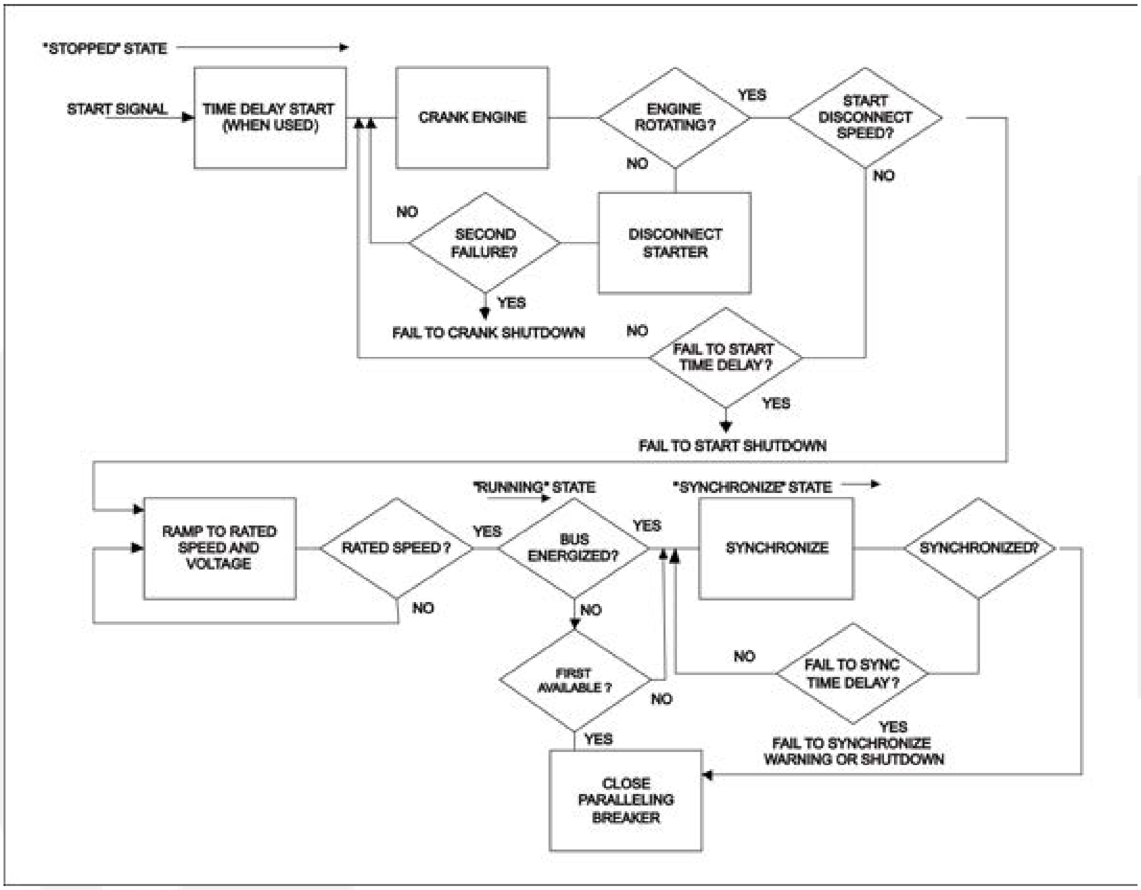

FIGURE 59. STARTING, SYNCHRONIZING, AND BREAKER CLOSURE LOGIC FOR A TYPICAL BLACK START SEQUENCE WITH A PARALLELED GENERATOR SET.

See Chapter 3 on page 17for more information on starting, synchronizing, and breaker closure logic.

When the generator set gets a signal to start, there may be a short time delay function programmed into the generator set control. This time delay is usually adjustable and may be adjusted to zero if the time delay is not desired or if there is a time delay on starting in another device, such as a transfer switch that provides the start command. Some system level controllers also have time delay functions built in, so that if the start commands are routed from the power transfer system to the master control and then to the generator sets the time delay to bring the system on line can be further lengthen. This is a potential issue in emergency applications where loads are required to be served within 10-15 seconds.

On completion of the time delay start, the control system will typically command that the engine starter be engaged, and check for engine rotation. When the control has verified that the engine is rotating, fuel is turned on so that the engine may start to fire and accelerate. Most control systems for engines incorporate controls to regulate fuel rate during cranking so that the engine does not get flooded with fuel that cannot be combusted due to incomplete engine firing. This improves the speed of starting and minimizes exhaust emissions, particularly particulate emissions during the starting process. Emission-controlled or certified engines often have complex control systems that precisely control the fuel rate based on conditions in the engine, combustion air flow, and other factors.

As the fuel begins to be fired, the engine accelerates, the starter disengages, and the engine fuel rate is regulated (ramped up) to drive the engine to rated speed. In general, the alternator excitation system is engaged shortly after the starter disconnects or when a specific speed is reached, so that as the engine accelerates, voltage will build up on the output terminals of the alternator. Many engine control designs now offer controls that allow adjustment of the speed ramping rate during starting. With a fast ramp the engine will start faster, but there is greater risk of overspeed and instability. With a slower ramp there is less risk of overspeed, fuel is more efficiently consumed so there are less emissions (such as smoke) and engine life is enhanced. Consequently, the best practice is to ramp as slow as practical, consistent with the needs of the site for time required to service to loads.

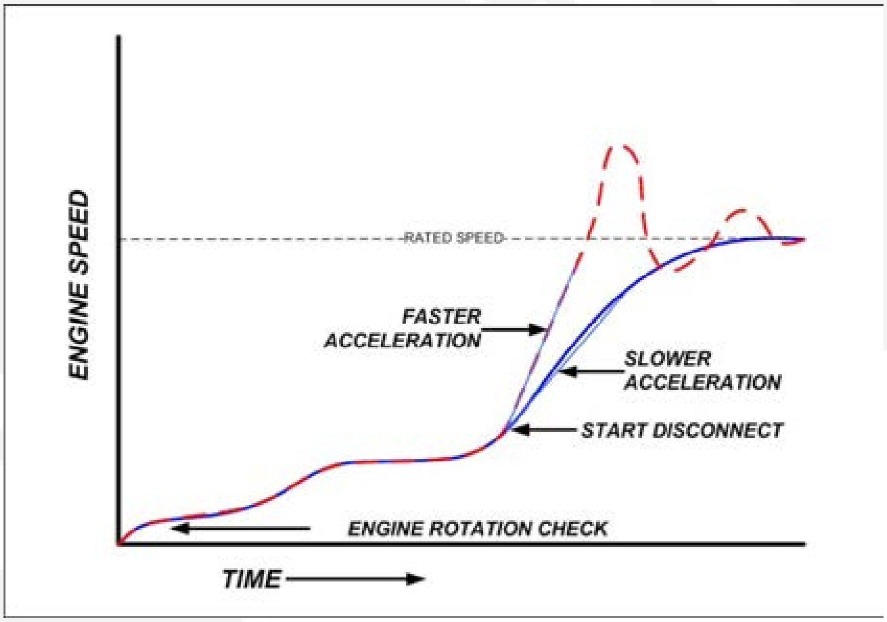

FIGURE 60. ENGINE STABILITY ON STARTING IS IMPACTED BY ACCELERATION RATE. FASTER ACCELERATION OFTEN RESULTS IN 'READY TO LOAD' SOONER, BUT SLOWER SYNCHRONIZING.

When the generator set is at rated speed and voltage the governor and voltage regulation systems monitor engine speed and alternator terminal voltage and regulate fuel rate and excitation level to maintain constant frequency and voltage. The engine is ready to accept load once it is at rated speed and voltage. The rate of load application that is acceptable on an engine is dependent on the type of engine, and other factors. In general, Cummins diesel engines can accept 100% of their rated capacity once the engine has reached rated speed, as long as the engine is kept at an adequate temperature through the use of properly designed and operating engine coolant heaters. Consult the manufacturer of the engine for recommendations on loading practice under black start conditions.

Generator sets using gaseous fueled engines may be limited in their ability to pick up load, so particular attention should be given to load management in applications using these engines.

5.10.1.1.1 Failure Modes and Variations in the Generator Set Starting Sequence

5.10.1.1.1.1 Cycle Cranking

Most generator sets are provided with a function that will allow the engine to crank for a programmed time period, and if it does not start, rest, and try cranking again. This practice helps to avoid starter damage with engines that are slow to start. The length of cranking duration and rest duration, and number of cycles are commonly adjustable. Consult the engine manufacturer to determine whether or not this function is desirable in your application. In general, with diesel engines it is desirable to continuously crank rather than cycle crank, as long as the starter is designed to handle it, since the diesel combustion begins at specific cylinder temperature and pressure levels, and these build as the engine continues to crank. The disadvantage of this is that the starter electrical windings will reach higher temperatures with a continuous crank cycle, and may prematurely fail if the starter is not designed for that duty cycle.

5.10.1.1.1.2 Fail to Crank Alarms

If an engine commands its starter to crank and the engine does not rotate, a “fail to crank” shutdown and lockout is commanded by the control. This protects the engine from damage due to starter mis-engagement, a locked engine, or other serious engine problems. Some designs will attempt engine cranking two times before initiating the shutdown and lock out of the engine. This is desirable, since a failure may be simply a failure to engage which can be rectified with a second chance to start.

5.10.1.1.1.3 Fail to Start (Overcrank)

If an engine will rotate with its starter, but fails to reach starter disconnect speed within an acceptable time period, the engine may be shut down and locked out on a “fail to start” shutdown. If the engine does not start, the starting batteries would eventually be consumed and repair would be more difficult and time consuming without this function.

More information on engine starting systems can be found in Cummins Power Generation document *T-030, Liquid Cooled Generator Set Application Manual*, chapter 4-15.

5.10.1.2 Dead Bus Closure of the First Generator Set

When a generator set in a non-paralleling application is approaching rated voltage and frequency, loads can be applied to the generator set. In paralleling application, however, the generator set typically starts with the paralleling breaker open. When multiple machines are starting simultaneously there is no common synchronizing reference, so before any machine can be closed to the bus one machine must be selected to be the first to close. (This machine is sometimes called the “lead unit”.)

Various schemes are used by different manufacturers to select the first generator set to close to the bus. A common, but archaic, system is called a “dead bus closing” system. In this arrangement if the generator set synchronizer does not sense bus voltage, it automatically closes the paralleling breaker and connects the generator set to the bus. In this arrangement it is possible for multiple machines in a system to initiate closing at one time, resulting in out of phase paralleling of the machines as they close to the bus.

Most system designers will avoid that problem using a control sequence that will select a single machine to be first to close based on being the first machine available, locking out other machines from closing, then closing the paralleling breaker on the selected machine. It is critical that the “fail to close” logic include provisions for the system to respond appropriately if the first machine designated to close to the bus does not close, or if the communication mechanism for the logic fails.

Once all the other machines in the system sense bus voltage available, their synchronizers are all simultaneously turned on. This results in machines synchronizing as fast as possible, so loads can be added as quickly as possible.

A critical feature of the system that selects the first machine to close to the bus is sensing that verifies that the paralleling breaker actually closes, so that if it does not, it can be shut down and another machine can be designated as first to close. Another common failure mode is failure of the paralleling breaker auxiliary contact (or contacts) that signal the control system to initiate load sharing or load govern functions. In either of these failure conditions, the system would start all the generator sets, but no generator set would close to the bus or pick up loads, so this is a serious problem that needs to be addressed to maintain system reliability.

5.10.1.3 Synchronizing

5.10.1.3.1 Generator Phase-Lock Loop Synchronizing (Isolated Bus)

With a voltage reference available and the synchronizer on, the control system will verify that the bus voltage is of acceptable level to synchronize, match the oncoming generator set output voltage to the bus voltage by manipulating the excitation control system, match the oncoming set frequency to the bus frequency, then compare phase angle between the oncoming generator set and the bus. If they are not in phase, the synchronizer provides a small engine fuel rate change to force them to synchronize. On finding the generator set synchronized, the fuel rated is maintained so that the oncoming machine stays synchronized with the bus. When the synchronizing check parameters are met, the synchronizer commands the paralleling breaker to close, completing the synchronizing process.

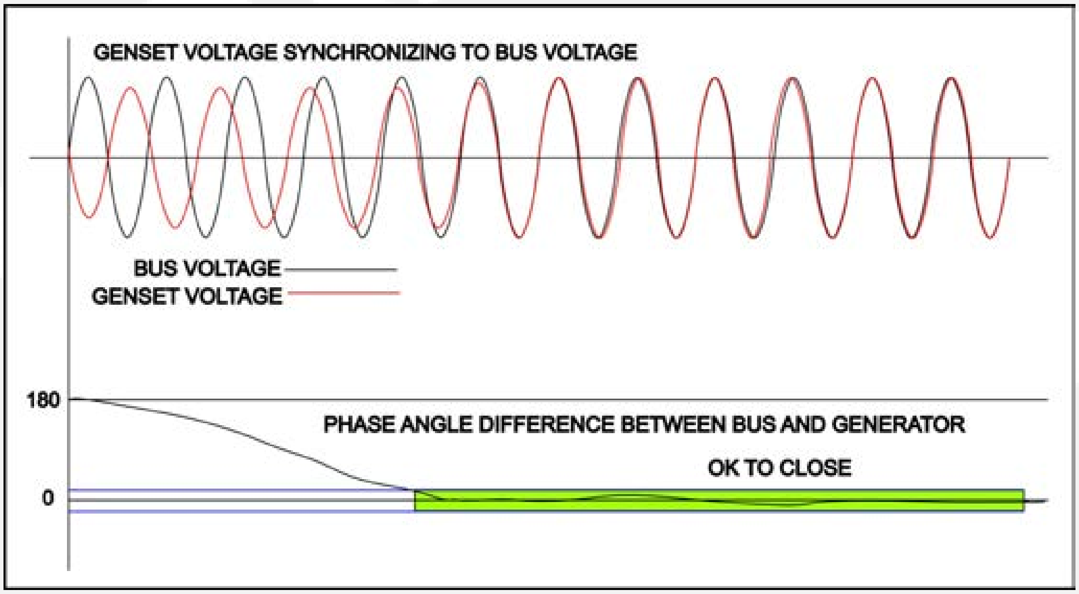

FIGURE 61. PHASE LOCK LOOP SYNCHRONIZER OPERATION. NOTE THAT THE BUS (BLACK SINE WAVE LINE) STAYS CONSTANT, BUT THE GENERATOR CHANGES SPEED AND VOLTAGE TO MATCH, THEN HOLDS IT IN SYNC UNTIL CIRCUIT BREAKER CLOSES.

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The sine waves at the top of the chart again show a typical generator and bus voltage. Note that frequency of generator set is varying, and frequency of bus is constant. (It actually is generally changing a bit, but for simplicity we are showing it as constant.) Peak voltage of generator set and bus is different at the start but that is ok. Here we show the impact of voltage matching during synchronizing, which makes the peaks of both waveforms match in magnitude.

Note that the generator set frequency is forced to the same time period as the bus, and is held there. The phase angle difference is not a constant slope, but changes quickly in either direction, as the generator set is actively controlled to match the bus.

Note also that the time in the sync check window is much longer. The generator set will stay synchronized for a long time, as long as generator set and bus frequency are not changed. It is common for load changes on a system bus to cause sudden change in phase angle difference, which effectively makes the sync process start over.

5.10.1.3.2 Generator Slip Frequency Synchronizing (Isolated Bus)

With a voltage reference available and the synchronizer on, the control system will verify that the bus voltage is of acceptable level to synchronize and match the oncoming generator set output voltage to the bus voltage by manipulating the excitation control system. The oncoming generator frequency is increased to a value that is approximately 0.1 hertz greater than bus frequency (adjustable), which results in the oncoming generator and the bus slipping in and out of frequency on a regular time sequence. A sync check device compares phase angle between the oncoming generator set and the bus. When the synchronizing check parameters are met, the synchronizer commands the paralleling breaker to close, completing the synchronizing process.

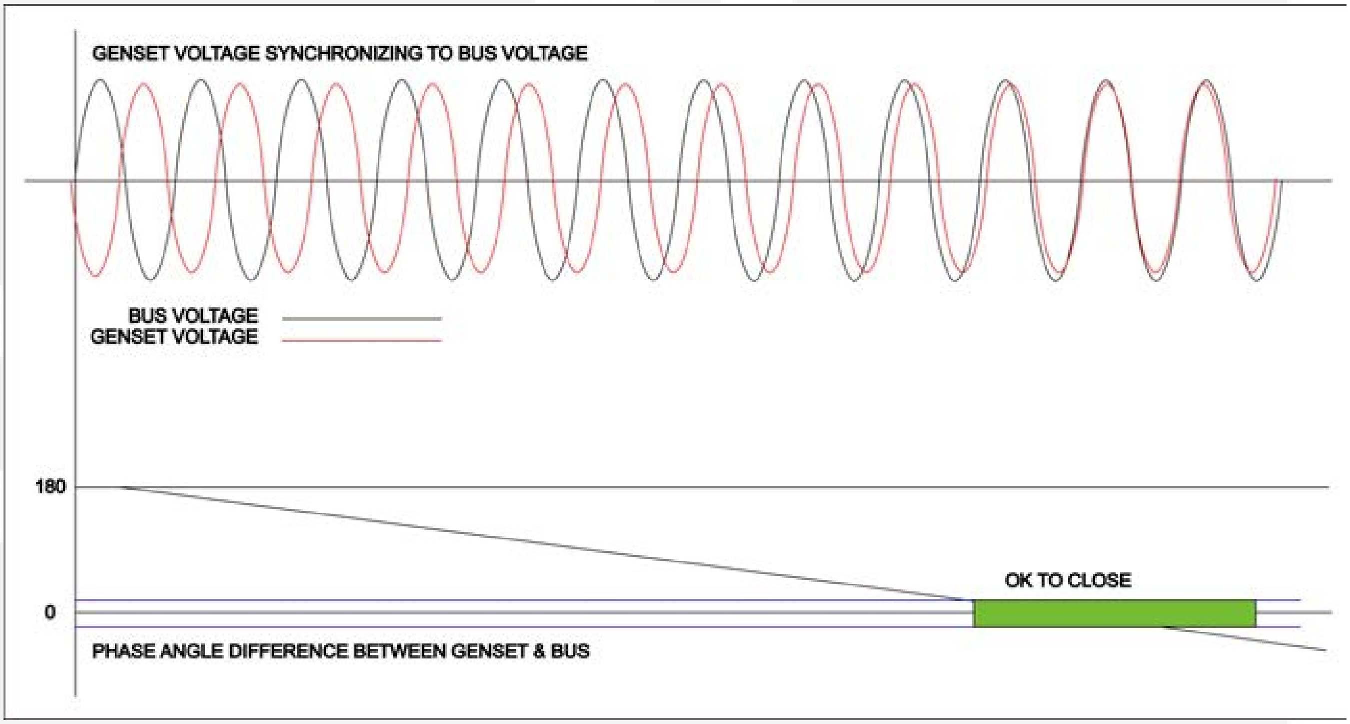

FIGURE 62. SLIP FREQUENCY SYNCHRONIZERS HOLD THE GENERATOR SET AT A CONSTANT, BUT DIFFERENT, SPEED FROM THE BUS.

Slip frequency synchronizing generally results in slower synchronizing than Phase-lock loop synchronizing, but is useful when engine frequency cannot be precisely controlled during the synchronizing process. Many gaseous fueled engines require use of slip-frequency synchronizing to reliably synchronize.

Slip frequency synchronizing can be used in both automatic and manual type synchronizing systems. It is also commonly used in closed transition transfer switches.

In manual synchronizing the operator will typically adjust the speed of the oncoming generator set slightly different than the bus (0.1 hz is common), and manually close the breaker when the sync check acceptance parameters are met. In closed transition transfer switches, the generator set frequency must be different than the utility frequency in order for the systems to synchronize. Most Closed transition transfer switches depend on the generator set to be pre-adjusted to a suitable frequency that is different from the utility for this to be achieved. In all cases, if the generator set voltage does not match the utility voltage, there will be a current flow induced between the sources at the instant of synchronizing. In active paralleling systems this is corrected by operation of the load sharing control system. In manual systems, the operator must make adjustments to “frequency” and “voltage” in order to balance load sharing. In fast (hard) closed transition ATS, the duration of current flow is so short it usually does not cause problems.

5.10.1.3.3 Failures Associated with Synchronizing Process

5.10.1.3.3.1 Fail to Synchronize

If a generator set is unstable, the system bus is exposed to continuous large load variations, or the system bus has excessive voltage waveform distortion, it may be difficult for a generator set to synchronize to the system bus. A timer begins timing when the synchronizing process starts to provide an alarm to the operator to call attention to the failure of the system to properly come on line. Most systems will allow a generator set to continue to attempt synchronization, because engines tend to become more stable as they warm up, making synchronization more likely.

Fail to synchronize is often related to an engine stability problem caused by fuel system deficiencies, but can also be caused by unrealistic sync check window settings.

In the event that failure is due to bus voltage distortion (which is evidenced by all machines able to synchronize at no load or with a load bank, and failing to synchronize to system loads; the generator set synchronizer may require changes or system loads may require more aggressive filtering to minimize waveform distortion. In some applications it may be acceptable to synchronize the generator sets before load is applied in order to prevent this failure mode. Fail to synchronize may be either a shutdown fault or a warning. Configuration as a warning is desirable as many causes of engine instability self-correct as the engine warms, allowing for eventual synchronization.

5.10.1.3.3.2 Synchronizer Range Failure

In order for a synchronizer to drive a generator set into its sync check “window”, the frequency, and optimally, the voltage, must be matched to the reference voltage. While the reference frequency and voltage do not vary significantly in a properly operating system, in an overloaded system the bus frequency may drop outside of the range of the protection devices while synchronizing due to the need to match the frequency of an overloaded generator set. This can be avoided by proper design of the load add sequencing of the system, and load shedding control systems that will drop non-critical loads when the system is overloaded for any reason.

A utility service, in particular, may be operating outside of the voltage range necessary to reach the minimum voltage difference parameter in the sync-check device.

The synchronizer and generator set control system should be designed to allow temporary operation in a range of -40 to 110% of nominal frequency and -10 to +10% of nominal voltage to allow the system to operate successfully through probable bus frequency and voltage conditions.

5.10.1.3.3.3 Over/Under Voltage or Frequency

In a similar fashion, a synchronizer can force a generator set to operate outside of the voltage and frequency limits set in its AC protective system in an attempt to quickly synchronize the generator set and to avoid transient current or power surges in the system. If the protection functions are set for too short of a time period, or the limits are set to values that are too tight, the synchronizer can drive the generator set to unnecessary failure while synchronizing. This problem is avoided in integrated systems by logically changing or turning off the protection settings during the synchronizing process. It can also be done by coordinating the functions of protective devices with an understanding of the timing and normal range of voltage and frequency excursions during the synchronizing state of the system.

It is particularly important to check protection settings when paralleling to the utility service, because voltage variation can be significantly wider than is typical in a generator set.

Over and under voltage/frequency conditions can also occur due to misadjustment of the control system by inadequately trained operators. Ironically, this can occur due to attempts to manually parallel a generator to the system. In integrated control systems this problem can be mitigated by inhibiting voltage and frequency adjustments during the synchronizing process, and ignoring any frequency or voltage adjustment after a generator is closed to the bus.

5.10.1.4 Load Management

Paralleling applications differ from single generator set installations in that the source of power is available in blocks, rather than all at once, as is true in most emergency/standby installations. Consequently, the control system must control the amount of load that is applied to the system to avoid overloading the available generator sets and to be sure that the most critical loads are served first (many local codes and standards require loads that impact on life safety to be served first when a power failure occurs).

System designers must split the system loads into priority levels based on the nature of the load, code requirements, and occasionally system needs. They also need to identify what mechanism will be used to add and drop loads from the system bus. Common selections include automatic transfer switches and feeder breakers. Some facilities will utilize a building management system to control loading when operating on the generator sets so that actual switching of the loads is not necessary (i.e., loads are turned on and off by the supervisory controls, rather than switching power supplies to the loads).

5.10.1.4.1 Load Add

The load add sequence begins when the first generator set closes to a parallel bus. With the first generator set available to accept load, the first block of loads can be added. When transfer switches are used, they sense bus voltage available and will automatically switch when their time delay transfer has expired, unless they are inhibited from operation.

As additional generator sets close to the bus, additional capacity is available to service loads, and they can be added.

When transfer switches are used for load addition (load priority) schemes, the paralleling control system often utilizes an inhibit function to prevent transfer switches from switching to the loads, even though they are sensing a good source on their alternate source sensing equipment.

5.10.1.4.2 Load Shed

Load shed may be implemented in two forms, the first, which is a normal sequence that automatically sheds loads to prevent overloads, and a second that will be initiated when a generator set is unexpectedly overloaded.

5.10.1.4.3 Failures Associated with Load Management System

Most failures associated with load management systems occur due to unexpected changes in loads, or mechanical or communication failures, in the operation of load add or shed devices. There are few impacts that can be made on these failures at the point of design, other than the use of redundant communication mechanisms (one example might be a hard-wired system backed up by a network arrangement) or by putting manual back up arrangements in the system, such as are shown in a typical touchscreen display for load management in the figure below (**Figure 63**).

FIGURE 63. A TOUCHSCREEN INTERFACE PANEL THAT ALLOWS MANUAL CONTROL OF LOAD STEPS.

5.10.1.5 Load Demand (Capacity Control) Systems

Load demand systems are provided to allow a paralleling system to automatically turn generator sets on and off as they are needed and as load on the system changes, to minimize fuel consumption and wear on the generator sets. They function by sensing total load on the system, comparing that to the total kW capacity of the generator sets that are paralleled on the system bus, and switching generator sets on and off as the load increases or decreases.

5.10.1.5.1 Failures Associated with Load Demand Systems

The failure of a load demand system will not impact on the reliability of a power system to a great degree (if load shed functions are properly implemented), but can result in an increase in fuel consumption in the system. Most common failures are related to improper settings for the load settings that drive when generator sets are switched on or off. There also are impacts if the system fuel supply is tainted (or other capacity-limiting failures occur in the generator sets) and the generator sets cannot produce rated power since the system operating decisions are made based on kW load measurements.

5.10.1.6 Power Transfer Systems

Systems that utilize generator sets for emergency or standby power necessarily need a mechanism for connecting loads to either the normal power or the generator power system. Power transfer systems can take many forms, especially in terms of the physical device that switches power from source to source. In sequence of operation, though, they are very similar. With the normal source powering the load, when a power failure occurs, the following sequence is initiated.

The normal source is sensed to have failed, and a short time delay period is initiated (time delay start), which verifies that the normal source has failed. This timing sequence is usually short, on the order of 1-3 seconds. When the time delay start is expired if the normal source has not recovered, a start signal is issued to the onsite power system. Note that sensing of normal source failure can be a function of a simple loss of voltage on any phase, and/or loss of frequency, and/or any one of several versions of individual phase failure devices. Start signals are commonly routed directly to the generator set (or sets), and also to the system master. In a system with many transfer switches, it is not uncommon for many start commands to reach the generator set at the same time. When errant start commands cause nuisance system starts, it may be problematic to find the source of the start command, unless transfer switches have logging capability to record the starting commands and other events. Use of transfer switches with integral event logs can help to simplify the necessary diagnostic process.

After the on-site system is sensed to be available (typically with voltage sensing equipment, or, voltage and frequency sensing), a second time delay, termed time delay transfer, is initiated. This time delay is intended to allow the on-site system to stabilize before loads are applied. Duration of this time period is also usually short, on the order of 1-3 seconds. When this period is complete, the normal source is disconnected, and the alternate source (the generator system) is connected to loads.

When the normal source has recovered, there is another time delay that is designed to verify that the utility service is positively returned. Typically this time delay is rather long, on the order of up to 30 minutes. Duration of this period is often related to the nature of the normal service to the facility. On completion of this time delay, the emergency source is opened, and an adjustable time period later, the normal source is closed. The duration of the “off” time is related to the nature of the loads in the facility. Safe transfer of inductive loads demands a longer transfer time than resistive loads.

The time period of transfer does not exceed approximately 1 second for motor loads up to about 200 hp when the system is properly adjusted.

When the system loads have all been retransferred to the utility service, the generator set runs for a short cooldown period. The purpose of this cooldown period is to allow engine components to cool down relatively slowly, which minimizes wear on the system. A typical cooldown period is dependent on engine manufacturers’ recommendations, but commonly will be on the order of 5-15 minutes. The time period can be shortened appreciably if the system loads are less than 30 percent of the standby rating of the generator set. Note that systems that utilize emission-controlled engines are likely to include a cooldown cycle within the engine control for the generator set. If this is the case, the supervisory system cooldown timer should be set at zero.

5.10.1.6.1 Transfer to the Generator Bus (Failed Normal/Utility Source)

FIGURE 64. PARALLELING SYSTEM

When the control system requires transfer of power to the generator sets bus, the normal source is available, and a “non-load-break” transfer is required, the following sequences are commonly used:

The generator bus main breaker is closed, connecting it to the normal source bus (in cases where it is isolated from the normal source bus by a generator bus main breaker), so that all generators can synchronize to the active utility service simultaneously. This generally allows faster synchronization and load acquisition by the generator bus, because the utility source commonly has a more constant frequency than an isolated generator bus.

Each generator set in the system is simultaneously commanded to start, it completes its starting sequence, and as it approaches rated voltage and frequency, the generator set paralleling control turns on its synchronizer. The synchronizer forces the individual generator set to match voltage and frequency to that of the system bus, and then slowly adjusts engine fuel rate to cause the generator set to be forced into synchronism with the utility service. When conditions are acceptable, the generator paralleling breaker is closed, and load is ramped to the generator set at a preset rate. A supervisory control system will monitor total load on the generator sets versus the utility service, and provide commands to the generator sets to maintain desired generator set load level so that power is not exported to the utility (or is maintained at a specific minimum level). The minimum load level requirement is necessary to maintain power flow from the utility when sudden load changes in the facility cause the generator sets to produce more power than is necessary to support facility loads.

Once the generator sets have all synchronized, closed their breakers, and ramped up their load level, the utility main breaker may be opened, isolating the on-site power system from the utility service. The decision of whether or not to stay connected is based on utility interconnection rules and whether the utility service is considered to be more reliable than the generator sets at the time of the paralleling. If the utility is more reliable staying connected will keep facility voltage and frequency matching that of the utility, which is desirable, since utility frequency and voltage will be more constant than the generator bus when load changes occur. On the other hand, if the utility fails while the generators are connected, depending on the failure mode, it may not be possible to disconnect the generator sets fast enough to avoid a general system failure.

The individual synchronizing time for the generator sets when paralleling to the utility during a transfer to the generator bus is generally in the range of 10-20 seconds when the generators are synchronizing to a live utility service, because each of them synchronizes individually with their own control rather than via a master synchronizer, which is slower; and, the utility frequency is very constant relative to a generator bus, which changes frequency significantly during load changes. Consequently, it is desirable to use a sequence of operation that allows the generator sets to synchronize individually rather than through a master synchronizer whenever possible.

5.10.1.6.2 Closed Transition Retransfer to the Utility (Normal Source) Bus

When the system requires transfer of power the generator sets bus, and a “non-load-break” transfer is required, the following sequences are commonly used:

Generator set bus synchronizing is used to allow exercise of generator sets in a system at a preset load level, initiation of interruptible power supply sequences, or transfer of power between the normal source the generator bus (either in anticipation of an impending power outage, or for return to the normal source after a power failure).

Since the generator sets are running in parallel and carrying system load with the utility main breaker is open, a master synchronizer is used to drive all generator sets simultaneously into synchronization with the utility service without upsetting the load balance between the machines. (Remember, attempting a speed or voltage change of one machine on an operating isolated bus will result in load change on that machine rather than a bus frequency or voltage change. See **Chapter 4 on page 55** for more information.)

The master synchronizer monitors utility voltage and frequency, and simultaneously forces the individual generator sets to match voltage and frequency to that of the system bus, and then slowly adjusts engine fuel rate to cause the generator sets to be forced into synchronism with the utility service. When conditions are acceptable, the utility main breaker is closed (causing generators to switch immediately to load govern state), and load is ramped to the utility at a preset rate by supervisory controls. When the generator bus is totally unloaded the generator main is opened.

When the generator bus is paralleled to the utility the load is ramped to minimum load level. This generally will occur over a 10 second or longer time so that transfer of power is imperceptible to system loads. When the time period of transfer is very short, such as in “fast” or “hard” closed transition transfer, the time in parallel to the grid is typically limited to 100 ms or less, which can result in frequency or voltage transients which can be disruptive.

If more than one utility main/generator main breaker pair is used in the system, the next master synchronizer in the system synchronizes across the second utility main, transferring additional load back to the utility. This process continues until all loads are transferred back. At that point the generator breakers are opened, and the engines run for a cooldown period and shut down.

The duration of synchronizing time for each utility main varies but is generally longer than the time of an individual machine synchronizing. A good expectation is that bus synchronizing should be achieved in not more than approximately 30 seconds. The additional time is not a serious problem, because both sources are available and a relatively slow, controlled process will result in minimum disturbance to system loads during the transfer of power.

5.10.1.7 Automatic Transfer or Retransfer Failure

It is a common practice to equip systems with manual transfer control capability, to allow manual operation of the system in the event that it does not automatically operate. When breaker pairs are used for power transfer, the manual transfer equipment includes an auto/manual switch, and manual breaker control switches to allow electrical control of the breakers. In the manual mode the system should not allow paralleling of the generator bus with the utility, since most utility service providers do not allow paralleling without active supervisory controls.

5.10.1.8 Manual Operation of Paralleling Controls

Note that manual operation as a backup to automatic controls is not practical for all control system operations. It is practical when the control function duplicated is not time sensitive and is limited in duration. So, it is not practical to manually back up a governor or voltage regulation system, but functions such as manual transfer of power and manual paralleling are possible.

Isolated bus paralleling systems are often provided with manual operation provisions that will allow generator sets to be manually paralleled if the automatic system present in each machine fails on one or more of the generator sets, or if the operator wishes to control the operation sequence of the system, such as during a commissioning process.

5.10.1.8.1 Manual Synchronizing at the Generator Set

If the system bus is operational and a generator is to be manually paralleled, the process is:

- Switch a generator set to the MANUAL mode and use the manual start switch to start the generator set and bring it to rated speed and voltage.
- Use the breaker close switch on the generator set control panel or in the master control (if provided) to manually close the generator's paralleling circuit breaker.
- Switch a second generator set to the MANUAL mode and use the manual start switch to start the generator set and bring it to rated speed and voltage.
- Use the breaker close switch on the generator set control panel or in the master control (if provided) to manually close the generator's paralleling circuit breaker. A display on the operator panel will indicate to the operator that the generator set can be safely closed. Note that the breaker close control switch (or switches) operate through a sync check device prevent manual operation that would cause out of phase paralleling.
- Manual Synchronizing from the Master Control

5.10.1.8.2 Manual Operation of Power Transfer Pairs

The system design for this configuration includes manual controls for synchronizing of the generator sets at the generator set and at the master control. The system will also include an auto/manual switch and manual operation switches with indicating lamps for each breaker in the transfer pair. Transfer pair breakers are electrically interlocked to allow only open transition of power from source to source. This is necessary under most stipulations of utility/mains supplier rules, since a manual operation would allow the generator sets to be connected to the grid with an unsupervised connection.

5.10.1.8.3 Manual Operation of Bus Ties

Manual operation of Bus Ties within a system is dependent on the system configuration and its operation. Typically this manual operation is achieved via one of two methods either at the Master Control or manually at the Bus Tie breakers themselves utilizing a physical key interlocking system. Should the method of manual operation be via the Master Control then the system will be configured to include an auto/manual switch and manual operation switches with indicating lamps for each Bus Tie breaker in the system. The assumption in this statement is that transfer is open transition, unless manual synchronizing equipment is also provided.

5.10.1.9 Breaker Failure

5.10.1.9.1 Paralleling Generator Set and Utility Breaker Failure

The control system monitors the position of the paralleling breakers via the auxiliary contacts and in doing so is configured to provide the following functions.

5.10.1.9.2 Breaker Fail to Close Warning

When the control system signals a circuit breaker to close, it will monitor the breaker auxiliary contacts and verify that the breaker has closed. If the breaker control does not sense a breaker closure within an adjustable time period after the initiation of the close signal. A fail to Breaker Fail to Close warning will be initiated.

5.10.1.9.3 Breaker Fail to Open Warning

The control system monitors the operation of breakers that have been signaled to open. If the breaker does not open within an adjustable time period after the initiation of the open signal, a “Breaker Fail to Open” warning will be initiated.

5.10.1.9.4 Breaker Position Contact Warning

The control system monitors both ‘a’ and ‘b’ position contacts from the breaker. If the contacts disagree as to the breaker position, a “Breaker Position Contact” warning will be initiated.

5.10.1.9.5 Breaker Tripped Warning

The control system accepts inputs to monitor breaker trip / bell alarm contact and will initiate a “Breaker Tripped” warning if it should be activated.

5.10.1.9.6 Fail to Disconnect Warning

If the controller is unable to open either breaker, a “Fail to Disconnect” warning is initiated. Typically this would be mapped to a configurable output, allowing an external device to trip the breaker that connects a specific generator set to the system bus.

5.10.2 Common Topologies

5.10.2.1 Isolated Bus (Active Synchronizing Systems)

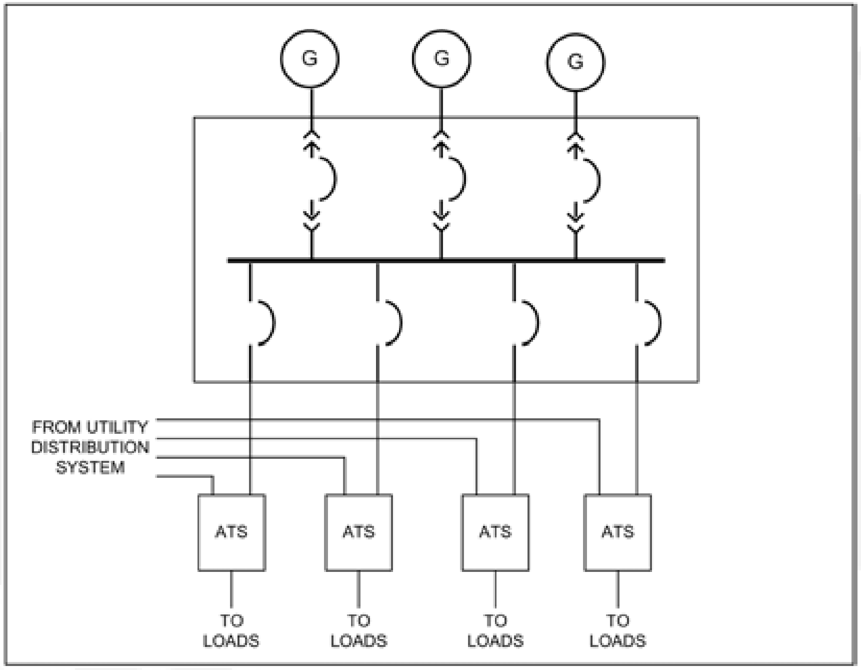

FIGURE 65. ISOLATED BUS SYSTEM AS IS TYPICALLY SEEN IN EMERGENCY/STANDBY APPLICATIONS.

Isolated bus paralleling systems are systems in which the generators operate in parallel but never parallel with the utility (mains) grid. (Except in cases where they are momentarily paralleled using high speed closed transition transfer switches. Because the switches operate in typically less than one tenth of a second from source to source, there’s limited need for load govern control.)

Isolated bus systems are by far the most common paralleling arrangements used. They are used in a wide range of situations for emergency/standby installations and also for prime power or temporary service using rental generator sets.

5.10.2.1.1 Isolated Bus Emergency/Standby Applications

When used in emergency/standby applications, the generator bus will typically be provided with normally closed manually operated feeder breakers which serve individual transfer switches. The transfer switches provide a good mechanism for load management, because unlike many circuit breaker types, they are specifically designed for switching loads but also have good short circuit withstand capability.

The sequence of operation for isolated bus systems is common for all multiple-generator systems that are used for emergency/standby applications on black start sequence.

Isolated bus paralleling systems, and all systems that are required to operate for emergency/standby purposes, require use of load management sequences to retain system reliability. These controls provide a means for the system to automatically add and shed load from the system bus as generator bus load-carrying capacity increases or decreases.

When transfer switches are used for load management, the lower priority transfer switches will be required to include provisions to allow the load management system to prevent the switch from connecting to the generator set bus until adequate generation capacity is available to serve their loads. The lower priority transfer switches also need the ability to switch to an “off” position for load shedding purposes. (Some ATS equipment is not able to switch to an “off” position. Systems that use this type of ATS should use feeder breakers for control rather than ATS, because a command to load shed would require the switch to connect to the utility source, which may not be failed but could have voltage quality that can damage loads, for example, a single phase loss for motor loads). Some designers specify use of these provisions for all transfer switches in the system, because they are not expensive to add at the time of purchase, and the provision allows more flexibility for future changes in the facility use. See Use of Feeder Breakers for Load Management (**Section 5.10.2.1.6.2 on page 142**) for more information on this option.

When planning the load management system, it is important that the load adding sequence adds load only as adequate capacity is available. The first loads added to the bus must be less than the capacity of the first generator set that closes to the bus. The smallest generator set in the system must be able to pick up all the first priority loads, or the smallest generator set must be restrained from being first on line.

Another alternative is to use a generator bus main breaker. This allows generator set synchronization before load is applied. This is not a good alternative for emergency systems, since a failure of the main breaker to operate would prevent any loads from being served.

5.10.2.1.2 Isolated Bus Systems for Prime Power

Isolated bus systems are also used for prime power in geographically isolated areas, and for some temporary generator set applications.

In these applications it is often not practical to actively control the load on the system, but equipment to manage the system (which amounts to a very small utility and distribution infrastructure) will require attention to the AC protective functions to protect the generator sets, and to manage the number and size of the generator sets that are connected to the loads, usually with the goal to minimize fuel consumption.

Prime power systems also benefit from remote monitoring arrangements that allow them to be operated with little active operator involvement other than normal generator set maintenance and dealing with abnormal conditions.

Prime power systems may also use a “clock correction" function so that AC-powered clocks connected to the distribution system keep accurate time.

5.10.2.1.3 Other Considerations

While isolated bus systems typically are not as likely to reach the practical limits of bracing systems available for switchgear, it is possible for that to happen. If the bus structure is not sufficiently braced for the available fault current of the generator sets needed, then the bus can be split and fed by different generators, and the tie only closed when additional capacity or redundancy is needed due to failures on the opposite bus, or limiting the fault current capacity of the necessary generator sets. In some cases a common redundant generator set has been used to support two or more parallel buses.

The steady state bus ampacity is a function of both the maximum current that can flow from the generator sources, and the maximum steady state load that can flow through the distribution devices. See **Section 4.5.7 on page 77** for further information on bus optimization.

In addition to planning for connection of known sources and loads for a project, it is desirable to maintain the capability of easily connecting a load bank for testing of generator sets and loads, and also provisions for connecting temporary generator set (or sets) in the event that one of the generator sets is disabled for an extended period for repairs or service.

5.10.2.1.4 Advantages and Disadvantages

- First generator set to start can serve loads immediately, so system can power first priority loads within 10 seconds in most applications.
- Any generator set can be first to accept load, so the service to the first priority loads is fast as is possible.
- The system is not delayed in service of loads by failure of any single generator set to start.
- If properly designed, these systems are usually the lowest cost paralleling arrangements, and the easiest to service over the life of a facility.
- Second and lower priority loads are not served until adequate generator capacity is available to serve them. The additional time required to synchronize and close to the bus, which is not present in single generator set systems, will be present. So, some loads will not be served until the last generator set is connected. This can take 20 seconds or longer from when the signal to start is issued.
- Since generator sets do not have utility paralleling functions in this type of system, there will be an interruption in service or potential disruption in system power quality when switching between the utility (mains) service and the generator bus.

5.10.2.1.5 System Operation Sequence (Emergency/Standby Application)

Under normal conditions the transfer switches connect all system loads to utility power, the generator sets are not operating, and their paralleling breakers are open. Feeders and other distribution devices on the emergency side of the system are normally closed.

5.10.2.1.5.1 Normal Power Failure with Open Transition Retransfer

- Individual transfer switches sense failure and complete time delay start sequence.
- Transfer switch (switches) send start command to generator set (or sets)
- Generator set (or sets) complete their individual time delay on starting (any time delay on starting that is integral to the generator set control system is typically set to zero) , start, and accelerate to rated frequency and voltage.
- If generator sets are paralleled, the first available generator set is selected and closes to the bus.
- All other generators synchronize to the bus and close as this occurs.
- Load add sequencing system begins adding load (or loads) to bus
- Generators begin load sharing and ramp to appropriate load level after they are individually closed to the bus
- Additional loads are added to the bus as capacity is available.
- Load control system and Load Demand system manage system loads and capacity.
- On return of normal power at each transfer switch, the switch will initiate a time delay to verify that utility has returned with acceptable reliability. On completion of that time delay in each switch, the switch retransfers to the normal source, and the switch removes its start command from the generator set (or sets).

- When all transfer switches have retransferred, and all start signals have been removed, the generator paralleling breakers open.
- Generator (or generators) operate for a cooldown period and shutdown, ready for another command to start.

5.10.2.1.5.2 System Exercise (With Load)

- Transfer switch (or switches) designated for exercise with load operation are signaled from the master control or SCADA/BMS system to start the exercise period, and complete time delay start sequence. [Transfer switches generally have exerciser clock functions internal to their control systems, so the designated ATS could be individually programmed for the appropriate exercise period. Use of a master device eliminates the need to reprogram each time a difference in the exercise equipment used is needed.]
- The system operates as described above in "Normal power failure and open transition transfer return." Note that only transfer switches designated for use in exercise service actually transfer loads.

When paralleling systems are used with generators and transfer switches, alternative exercise sequences can be devised in which only one generator is exercised at a time, and sufficient switches are operated to fully load the machines. This will often result in a more productive exercise sequence, but often involves operator supervision.

5.10.2.1.5.3 System Test (Without Load)

System test without load is the same operational sequence as the exercise with load sequence, except that the transfer switches do not connect to the generator bus.

5.10.2.1.6 Common Variations to Isolated Bus Design

5.10.2.1.6.1 Isolated Bus with Main Breaker

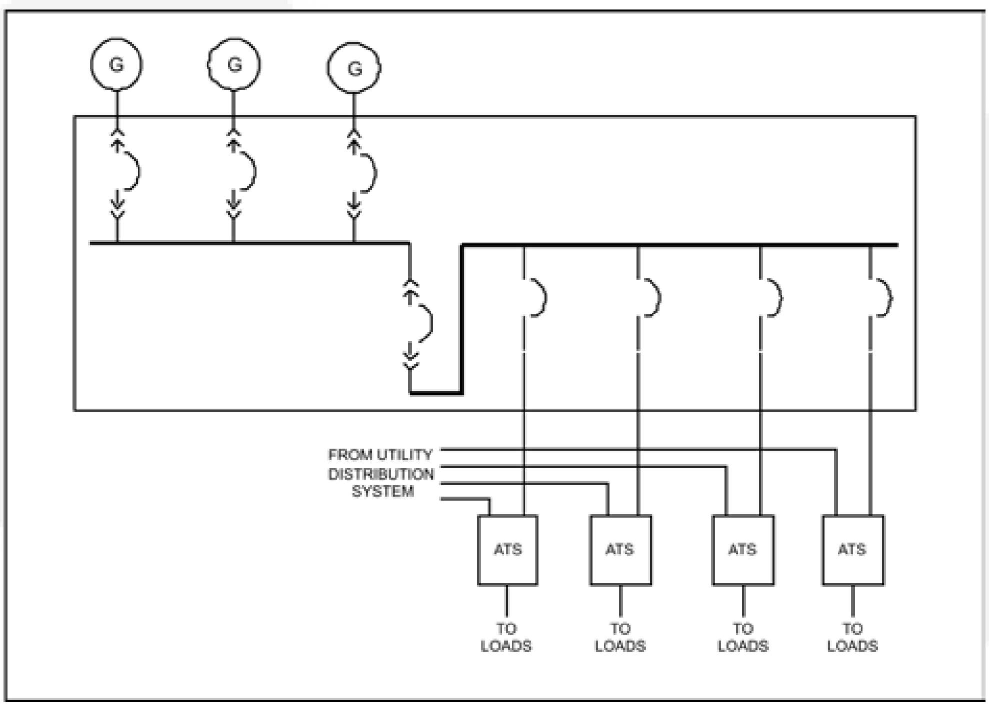

FIGURE 66. ISOLATED BUS SYSTEM WITH GENERATOR BUS MAIN BREAKER, SERVING TRANSFER SWITCHES.

Occasionally isolated bus paralleling systems may be equipped with a main bus circuit breaker. The main bus breaker, when electrically operated, allows the system to parallel multiple generators before any loads must be served. It should be noted that load management systems can perform this function without the expense of the additional main breaker, so main breakers are mostly used when feeder distribution is not integral to the paralleling switchgear, when the use of lower cost (non-electrically operated) feeders are desired, or remotely controlled transfer switches are not available.

A manually operated main breaker may be used when distribution equipment is not integrated into the switchgear, but rather is remote from the paralleling equipment. In that case, the system will operate exactly like other isolated bus systems.

5.10.2.1.6.2 Use of Feeder Breakers for Load Management

Most medium voltage systems and some low voltage power systems (those using ATS equipment not capable of being effectively employed in a paralleling system load management scheme because they are not capable of switching to a neutral position) may use electrically operated feeder breakers for load management.

When feeders are used for load management, the hardware used should be capable of switching reliably for at least 3000 cycles, based on use in a standby application as defined in ISO 8528. Consideration should be given to whether the feeder devices should be drawout type, based on the probability of needing to replace a breaker while the system is in service. If the system is intended to operate for a long time (days or weeks) during a normal power failure, it is likely that drawout breakers are a good choice. If the system is primarily used for emergency evacuation of a facility, or the breakers can be isolated for repair, a drawout may not be as important.

AC closing and DC tripping (DC from the generator starting batteries/control system) are common features in these breakers, in order to eliminate the need for an additional battery string to support the system, and also to eliminate batteries as a source for failure of the system.

When used as load management devices, the strategy for sequence of operation is similar to that used for transfer switches. The control system provided should provide a means to change the sequence when necessary. This can be done with “hard-wiring” or may be done with a configurable control system, depending on the expectation of the number of changes that may be necessary in the life of the facility.

5.10.2.1.6.3 Isolated Bus for Prime Power

Isolated bus prime power systems are commonly used in applications where there is not a local utility service supplier, and the generator paralleling system is the only power source available. They may also be used in temporary facilities, often using rental generator sets, when the normal power supply is unavailable or being maintained. The one line configuration is electrically similar to other isolated bus systems, but paralleling breakers may not be inside a switchboard but rather in a generator set enclosure.

In general these systems are often more simple in design than many other isolated bus applications, in that there is rarely a need for load management systems in this design and there are usually not transfer switches in the system.

There are usually needs for capacity management, and use of multiple generators of various different capacities, to enable best practical fuel consumption rate for the system. (Fuel costs are often the highest cost of operating in these systems.)

Remote monitoring and management are also desirable in many cases.

5.10.2.1.6.4 Isolated Bus (Exciter/Dead Bus Systems)

Exciter paralleling is the most basic and traditionally the least expensive of the automatic paralleling systems. An exciter paralleling system requires no operator intervention to start and parallel the generator sets.

Exciter paralleling systems have often been used when it is desired for the system to be on line quickly, and the cost of the equipment is important. When both generator sets start quickly, the system will pick up all loads quickly, but if one unit doesn't start, the system must wait for the slower starting unit to either start or completely fail before the system can respond. Consequently, the system is not often used for critical or life safety applications.

Cost is limited by the use of simple relay logic and by the elimination of busing and a master/totalizing control.

Because the paralleling breakers are normally closed and are not used for active switching, exciter paralleling systems can use the less expensive molded case circuit breakers. The system does not require the use of 5-cycle operators on paralleling breakers.

The controls are limited and molded case breakers are relatively small, and there is no need to isolate the controls from the breakers, so the cabinets in exciter paralleling systems are compact. It is not necessary to locate the cabinets together, as they may be located at their respective generator sets.

Floor space requirements are considerably less for front-connected stationary breaker arrangements than for drawout breaker arrangements.

Because exciter paralleling systems use readily accessible components and simple logic, they are easily serviced.

If a generator set fails to start, the speed of load assumption is affected. The system must sense the failure and shut down and lock out the failed set before voltage can build up and load can be added to the bus.

When the system is used to manually parallel a generator set to a live bus, the operator manually adjusts the frequency and voltage to the system bus, which results in the load sharing settings of the system being changed. Consequently the operator must always adjust the load sharing between the generator sets after manual paralleling. This may be a more difficult process than most operators would care to use and may have a great deal of difficulty in understanding.

System operation is limited to a standard operating scheme. The exciter paralleling system does not utilize a programmable controller, which would allow it to perform more sophisticated functions such as load demand, load priority and load shed, as most random access systems do.

This, along with the availability of higher technology control systems at lower cost and the need for isochronous governing is gradually eliminating the use of this type of control system in new installations.

5.10.2.1.6.4.1 Advantages and Disadvantages

- Least expensive automatic paralleling system.
- Relatively small physical size
- Breakers are normally closed (so there is less wear during normal operation), and do not require high speed operators, and thus often do not have drawout structures.

- Logic is simple and easy to accomplish without customized PLC programs that may be difficult to support in the field, or maintain over the life of a facility.
- Fastest possible service to all loads, unless a generator set fails to start.
- Extremely limited ability to load add/shed sequences

5.10.2.1.6.4.2 Sequence of Operation

In an exciter paralleling system, with the system ready to operate in an emergency-standby mode the paralleling breakers are normally closed and the exciter field breakers are open. (Consequently, when the generator sets are started, they accelerated to rated speed, but produce no voltage until the exciter is enabled.)

Normal Power Failure with Open Transition Retransfer

- Individual transfer switches sense failure and complete time delay start sequence.
- Transfer switch (or switches) send start command to generator set (or sets)
- On receipt of start command, the engines crank, start, and accelerate to start disconnect speed. Generator set (or sets) typically do not use individual time delay on starting since the system requires all the generators to start at one time.

  speed. Generator set (or sets) typically do not use individual time delay on starting since the system requires all the generators to start at one time.
- When all generator sets have reached start disconnect speed, the exciter circuits on all generators close.

  generators close.
- The generators simultaneously ramp to rated voltage, and are synchronized and paralleled in the process.

  in the process.
- Load sharing begins to function (often using droop).
- Transfer switches complete their individual time delay on transfer and connect their loads to the generator sets. Load management is typically achieved by use of different time delay on transfer for each ATS, with higher priority loads using shorter time delays.
- On return of normal power at each transfer switch, the switch will initiate a time delay to verify that utility has returned with acceptable reliability.
- On completion of that time delay in each switch, the switch retransfers to the normal source, and the switch removes its start command from the generator set (or sets).
- When all start signals have been removed, the generator exciter field breakers are opened.
- Engines operate for a cooldown period and shutdown, ready for another command to start.

Exercise and Test Modes

Test mode uses the same operational procedure as normal power failure, except that the ATS test mode is used to initiate the sequence.

Exercise is accomplished using the “test with load” function in the ATS.

5.10.2.2 Emergency-Standby with Utility (Mains) Paralleling

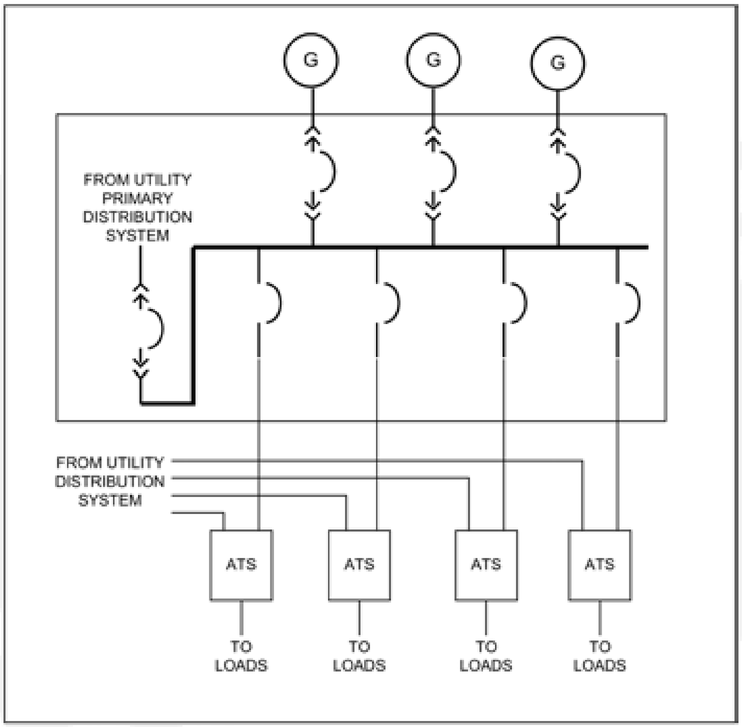

FIGURE 67. EMERGENCY/STANDBY SYSTEM WITH UTILITY PARALLELING CAPABILITY VIA A SEPARATE CONNECTION TO THE FACILITY PRIMARY DISTRIBUTION SYSTEM.

Systems of this type are commonly used in situations where it is desired to use an emergency/standby generator set in an interruptible rate agreement with a local electric service provider, or when it is desired to exercise a generator set using a paralleling interface to the utility. In this system the utility normally powers critical loads through automatic transfer switches. These switches can incorporate bypass functions, but will commonly be conventional mechanically interlocked switch designs. They will function as with typical transfer switches, so that when power fails the utility paralleling breaker is opened, generator set is started and the loads are transferred to the generator set as soon as it is available. Note that not all system loads are served in this arrangement.

For exercise purposes, transfer switches can be signaled to switch their loads to the generator set so that it can be properly loaded for the exercise period. (Many transfer switches incorporate exercise functions so that they can initiate exercise, also.) Another alternative is to add a utility paralleling breaker and use the utility for the “load bank”. During a test period, the generator set is started, and brought to rated speed and voltage. The generator set is then synchronized with the utility across the parallel intertie circuit breaker, and the breaker is closed. The generator set then ramps up to a predefined load level for a test period. The generator set exports power into the normal distribution system without disrupting normal power to loads. Controls can be provided that will prevent exporting power to the local utility.

If the utility fails during an exercise period, the protective relaying in the utility distribution equipment would operate to isolate the utility from the generator set by opening the intertie breaker. The transfer switches would sense a general power failure and immediately transfer to the generator set.

If the utility power fails during an exercise period without the intertie device, service to emergency loads is first priority, so exercise loads may need to be turned off so that the emergency loads can be fed.

When the utility power returns, the transfer switches automatically return to that power source.

The system also has needs for testing, so a general test of the entire system, with operation of all transfer switches to the generator set in the prescribed sequence, should be done at least annually, or as required by local codes and standards.

5.10.2.2.1 Advantages and Disadvantages

- Emergency and standby loads have dual paths to be served by on site power.
- Generator set is always exercised at a known, predefined load level.
- Generator set is exercised under load without disrupting power to critical loads.
- Generator set power supplements utility, so cost of test is reduced by the value of the electricity produced by the generator set.
- Generator set can be used for interruptible service contract if desired by customer and utility.
- Not all system loads are supported by generator power during a power failure, and the loads that are supported by emergency/standby power will still have a power interruption when they operate.

5.10.2.2.2 Sequence of Operation

Under normal conditions the transfer switches connect all system loads to utility power, the generator sets are not operating, and their paralleling breakers are open. Feeders and other distribution devices on the emergency side of the system are normally closed.

5.10.2.2.2.1 Normal Power Failure with Open Transition Retransfer

- Individual transfer switches sense failure and complete time delay start sequence.
- Transfer switch (switches) send start command to generator set (or sets)
- Generator set (or sets) complete their individual time delay on starting (any time delay on starting that is integral to the generator set control system is typically set to zero) , start, and accelerate to rated frequency and voltage.
- If generator sets are paralleled, the first available generator set is selected and closes to the bus.
- All other generators synchronize to the bus and close as this occurs.
- Load add sequencing system begins adding load (or loads) to bus
- Generators begin load sharing and ramp to appropriate load level after they are individually closed to the bus
- Additional loads are added to the bus as capacity is available.
- Load control system and Load Demand system manage system loads and capacity.
- On return of normal power at each transfer switch, the switch will initiate a time delay to verify that utility has returned with acceptable reliability. On completion of that time delay in each switch, the switch retransfers to the normal source, and the switch removes its start command from the generator set (or sets).

- When all transfer switches have retransferred, and all start signals have been removed, the generator paralleling breakers open.
- Generator (or generators) operate for a cooldown period and shutdown, ready for another command to start.

5.10.2.2.2.2 Interruptible (Curtailable) Sequence

- System receives a signal to start in interruptible/curtailment state.
- Generator set (or sets) complete their individual time delay on starting (any time delay on starting that is integral to the generator set control system is typically set to zero), start, and accelerate to rated frequency and voltage.
- Generator bus tie breaker to utility source closes.
- Generator (or generators) synchronize to the bus and close as this occurs.
- As each generator set closes, it ramps to its commanded load level. (The commanded load level may be preset, or provided via a control monitoring conditions at the utility service.)
- When interruptible/curtailment signal is removed, each generator individually and simultaneously ramps to no load over a pre-set time period.
- On reaching a no load condition, the generator paralleling breaker opens.
- Generator (or generators) operate for a cooldown period and shutdown, ready for another command to start.

5.10.2.2.2.3 Exercise and Test Modes

- Exercise mode is accomplished by use of the same operational procedure as used in the Interruptible sequence.
- Test mode uses the same operational procedure as normal power failure, except that the ATS test mode is used to initiate the sequence.

5.10.2.3 Transfer Pair (Single Generator Set)

The single generator set version of transfer pair is distinguished from multiple generator set version because all control can be accomplished within the single generator set controller.

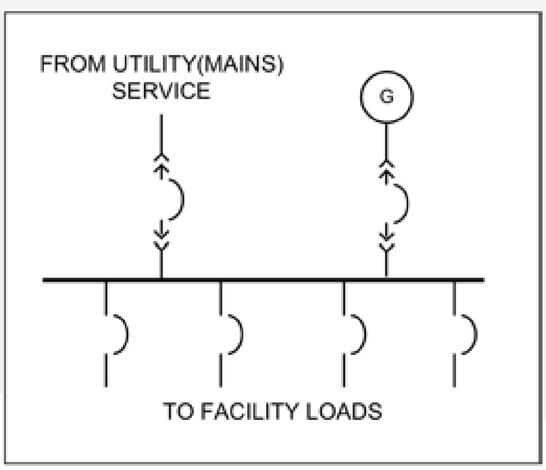

FIGURE 68. TRANSFER PAIR SYSTEM WITH SINGLE GENERATOR SET SERVING FEEDER CIRCUIT BREAKERS.

A common arrangement used when a generator set is added to an existing facility is a single generator set/transfer pair. The topology is often chosen because it requires no reconfiguration of the facility distribution system and minimum disruption to the operation of the facility for starting up the system. The system operation can be open transition, fast closed transition, or soft ramping closed transition. The systems can be designed to operate the generator set in a peak shaving arrangement (load on the utility is held to some constant value or base loading where load on the generator set is held to a constant value.

Non–load break transfer systems are often used in applications where the power interruption that occurs on transfer of a conventional transfer switch causes system operational problems (such as nuisance motor shutdowns, data loss, etc.).

The controls necessary to provide these different sequences of operation are often integrated into the generator set controller. The generator set then is termed to include Power Transfer Control (PTC).

This equipment may be appropriate in computer/data processing systems, manufacturing facilities (especially involving process control), or in industrial facilities for interruptible applications.

On–site power systems that are required by code to be tested on a regular basis must be interrupted so that the on–site power system demonstrates its ability to assume all critical loads under true power failure conditions.

Because non–load break transfer systems complete the transfer of power without disrupting the service to inductive loads, there is less transient load on the on–site power system when they are transferred in a non–load break mode than when they are transferred under outage conditions.

Non–load break systems allow exercising on–site power systems without a total power interruption. Exercising the on–site power system is essential to maintaining the system in peak operating condition.

The system will often require service entrance provisions on the utility side of the system. There may not be a need for UL listing of the system as a transfer switch, as in many cases these systems do not serve emergency or legally required loads. Note that if the facility does require the use of emergency system loads, it would be more appropriate to use a Emergency-Standby System with Utility (Mains) paralleling system design, if emergency and other loads are required to be segregated from one another.

Switchgear is often installed out of doors, which may require heating or cooling and anti condensation protection in the switchgear equipment. The system design should be carefully reviewed to be certain that all equipment provided is capable of operating under the environmental conditions present in the equipment.

It is particularly desirable to use drawout breakers in this arrangement, so that the system can be serviced without interrupting power to the facility. This is particularly true on systems using larger breakers (>1000 amps), since these are more difficult for a single technician to handle alone.

5.10.2.3.1 Advantages and Disadvantages

- Lowest cost means to provide full facility generator backup power.
- Can be configured for load transfer without a disturbance. Where the local utility service provider allows paralleling of the generator bus to the utility service for at least 10 seconds, the system provides a means to transfer loads to the generator bus and back to the utility without disrupting operation of sensitive loads.

- Since the system power transfer functions are provided within the system design, it is often one of the less expensive ways to provide a factory built and fully assembled system, since it doesn't require transfer switches which would require more field wiring.
- Additional equipment is required to serve emergency loads. Emergency/Standby loads can be served by independent ATS equipment located downstream from the feeder breakers fed by the transfer pair.

5.10.2.3.2 Sequence of Operation

Under normal conditions the transfer breaker pair connects all system loads to utility power and generator power, the generator set is not operating and paralleling breaker is open, and the generator main breaker is open. Feeders and other distribution devices are normally closed. Feeders may be electrically operated to allow sequence of load adding and shedding. Breaker pair configurations are often designed to be configurable from open transition to closed transition. The ability to change operating sequence is useful in some cases, where utility approval of the paralleling version of the system is not available at the time of installation, but may be desirable at some future point in the system's life.

5.10.2.3.2.1 Normal Power Failure with Open Transition Retransfer

- The Transfer Control System senses failure of the utility source and completes time delay start sequence.
- Generator set is commanded to start.
- Generator set completes its individual time delay on starting (any time delay on starting that is integral to the generator set control system is typically set to zero), start, and accelerate to rated frequency and voltage. Some generator sets will start through an idle speed cycle, or start and ramp to rated speed.
- The system time delay on transfer is completed, and the utility breaker opens. A programmed transition time delay verifies that the loads are disconnected for a preset period of time.
- Generator breaker closes and assumes connected system loads. The sequence should include an intentional time delay to allow voltage from inductive loads to decay prior to connecting an alternate source.
- On return of normal power the control system will initiate a time delay on retransfer to verify that utility has returned with acceptable reliability.
- On completion of the time delay retransfer the generator breaker opens, and after the time delay programmed transition is completed the utility breaker closes.
- Generators operates for a cooldown cycle and shuts down, ready for another command to start.

5.10.2.3.2.2 Normal Power Failure with Closed Transition Retransfer

- Control system senses failure of the utility source and completes time delay start sequence.
- Generator set is commanded to start.
- Generator set completes its individual time delay on starting (any time delay on starting that is integral to the generator set control system is typically set to zero), start, and accelerate to rated frequency and voltage. Some generator sets will start through an idle speed cycle, or start and ramp to rated speed.

- The system time delay on transfer is completed, and the utility breaker opens. A programmed transition time delay verifies that the loads are disconnected for a preset period of time.
- Generator breaker closes and assumes connected system loads. The sequence should include an intentional time delay to allow voltage from inductive loads to decay prior to connecting an alternate source.
- On completion of the time delay retransfer the system will verify synchronization of the generator set with the utility service, and then close the utility breaker, paralleling the generator set with the utility service.
- The system ramps generator load to zero load, and on reaching the programmed minimum power condition it will open the generator paralleling breaker.
- Generator operates for a cooldown cycle and shuts down, ready for another command to start.

5.10.2.3.2.3 Exercise and Test Modes

Transfer pair control systems commonly include an exerciser clock, which can be programmed to initiate system exercise at pre-programmed times. The system also may be commanded to exercise mode from an external control system. Operation is the same regardless of where the exercise command is issued.

The transfer control system or remote device initiates an exercise period by sending start command to generator set. At the completion of the exercise period the command will be removed, allowing the system to return to normal utility service.

The system operates as described above in "Normal power failure and open transition transfer return" or "Normal power failure and closed transition return".

5.10.2.4 Transfer Pair (Paralleled Generator Sets)

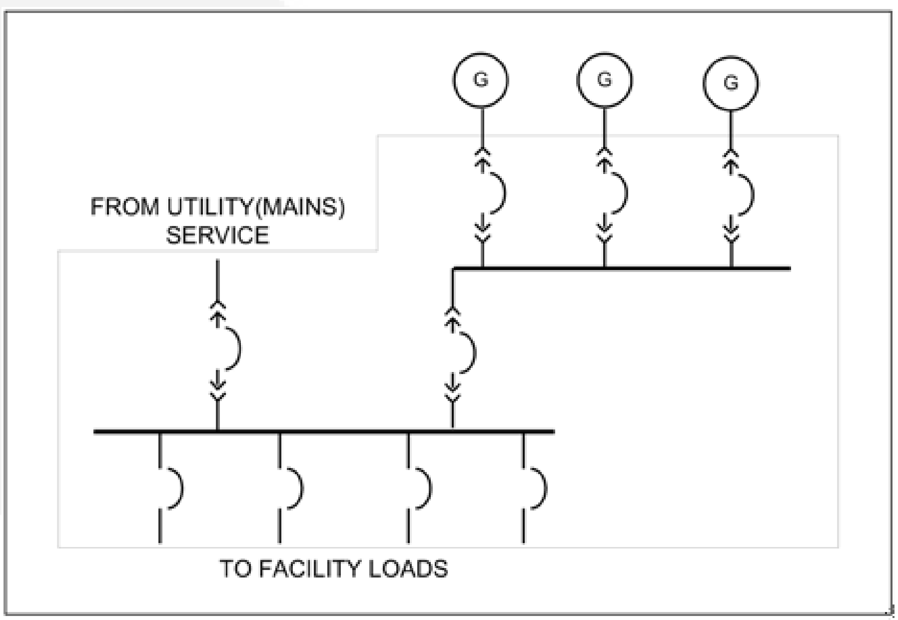

FIGURE 69. TRANSFER PAIR SYSTEM WITH UTILITY MAIN/GENERATOR BUS MAIN TRANSFER PAIR SERVING FEEDER CIRCUIT BREAKERS.

In this configuration a system load bus is fed by an electrically operated utility main breaker and an electrically operated generator parallel bus main breaker. The utility main breaker and generator parallel bus main breaker work together like a transfer switch to provide power transfer functions for the entire system.

Systems of this type are often used in medium voltage applications and in applications where an entire facility is fed generator power. These systems are often seen in interruptible power applications, cogeneration sites, or when the normal utility service is unreliable.

Transfer pair configurations are ideally suited to “soft” ramping closed transition operation, so loads can be transferred between good sources with nearly imperceptible variation in voltage and frequency of power provided to loads.

In order to maintain system reliability in the event that the power transfer system fails, the transfer pair should be provided with an auto/manual switch, breaker open/close indications, source available indications, and manual breaker control switches. It is also best practice mount manual operation instructions local to these manual control provisions.

5.10.2.4.1 Advantages and Disadvantages

- Where the local utility service provider allows paralleling of the generator bus to the utility service for at least 10 seconds, the system provides a means to transfer loads to the generator bus and back to the utility without disrupting operation of sensitive loads.
- Since the system power transfer functions are provided within the system design, it is often one of the less expensive ways to provide a factory built and fully assembled system, since it doesn’t require transfer switches which would require more field wiring.
- All loads are served by two sources, so there is inherent redundancy of service in the system. If one service fails, the other automatically takes over.
- By using power circuit breakers in drawout carriages, it is easy service the power transfer contacts. A single spare breaker can be provided, making the system functionally equal or better to a transfer switch with manual bypass.
- Not commonly used on smaller systems (rated less than 800 amps steady state), because of the service difficulty and durability of most molded case breakers.
- Ground fault protection can be incorporated to the transfer pair breakers, but will malfunction when 3-pole switching is used. (While operating on generator power, the system may not be able to sense a ground fault on the generator, and may nuisance trip the utility source breaker.) When ground fault is required, either 4-pole switching should be used, the ground fault protection should be moved to downstream to feeder breakers, or an alternate ground fault protection scheme should be used.
- Load management is generally accomplished with electrically operated feeder breakers.
- For U.S. applications where Emergency and Legally Required loads are served from the generator system, these loads must be physically isolated from Optional Standby loads. The required isolation is not possible unless the Emergency and Legally Required loads are served by transfer switches fed from feeders directly connected to the generator bus. This will result in additional costs, and result in some loads actually being exposed to interruption in power when both sources are available, unless closed transition transfer switches are used.

5.10.2.4.2 Sequence of Operation

Under normal conditions the transfer breaker pair connects all system loads to utility power, the generator sets are not operating and paralleling breakers are open, and the generator main breaker is open. Feeders and other distribution devices are normally closed. Feeders may be electrically operated to allow sequence of load adding and shedding. Breaker pair configurations are often designed to be configurable from open transition to closed transition. The ability to change operating sequence is useful in some cases, where utility approval of the paralleling version of the system is not available at the time of installation but may be desirable at some future point in the system's life.

5.10.2.4.2.1 Normal Power Failure with Open Transition Retransfer

- The Transfer Control System senses failure of the utility source and completes time delay start sequence.
- All Generator sets are commanded to start.
- Generator set (or sets) complete their individual time delay on starting (any time delay on starting that is integral to the generator set control system is typically set to zero), start, and accelerate to rated frequency and voltage. Some generator sets will start through an idle speed cycle, or start and ramp to rated speed.
- The first available generator set is selected and closes to the bus.
- All other generators synchronize to the bus and close as synchronization occurs.
- Generators begin load sharing and ramp to the same percent of load after they are individually closed to the bus.
- The system time delay on transfer is completed, and the utility breaker opens. (The control system is generally configured to allow the utility breaker to open and initiate transfer when a predetermined number of generator sets have closed to the bus.)
- Generator bus main breaker closes and assumes connected system loads. The sequence should include an intentional time delay to allow voltage from inductive loads to decay prior to connecting an alternate source.
- As generators close to the bus, additional feeder breakers are commanded to connect to the generator bus.
- Load control system and load demand system manage system loads and capacity.
- On return of normal power the control system will initiate a time delay on retransfer to verify that utility has returned with acceptable reliability.
- On completion of the time delay retransfer the generator breaker opens, and after the time delay programmed transition is completed the utility breaker closes
- Generators operate for a cooldown cycle and shut down, ready for another command to start. The cooldown cycle is typically programmed into each generator set controller and is dependent on many factors, so they may not all shut down at the same time.

5.10.2.4.2.2 Normal Power Failure and Closed Transition Return

- The Transfer Control System senses failure of the utility source and completes time delay start sequence.
- All Generator sets are commanded to start.

- All Generator sets start (any time delay on starting that is integral to the generator set control system is typically set to zero), and accelerate to rated frequency and voltage. Some generator sets will start through an idle speed cycle, or start and ramp to rated speed.
- The first available generator set is selected and closes to the bus.
- All other generators synchronize to the bus and close as synchronization occurs.
- The system time delay on transfer is completed, and the utility breaker opens. (The control system is generally configured to allow the utility breaker to open and initiate transfer when a predetermined number of generator sets have closed to the bus.)
- Generator bus main breaker closes and assumes connected system loads. The sequence should include an intentional time delay to allow voltage from inductive loads to decay prior to connecting an alternate source.
- Load control system is enabled, and the system adds load by operating feeder breakers as generator capacity becomes available.
- Load Demand system manages system capacity.
- On return of normal power the control system will initiate a time delay on retransfer to verify that utility has returned with acceptable reliability. The system will synchronize the generator set bus output to the utility when the utility source is sensed to be good.
- On completion of the time delay retransfer the system will verify synchronization of the generator set bus with the utility service, and then close the utility breaker, paralleling the generator sets with the utility service.
- The system ramps generator bus load to zero load, and on reaching the programmed minimum power condition the generator bus breaker will open.
- Generators operate for a cooldown cycle and shut down, ready for another command to start. The cooldown cycle is typically programmed into each generator set controller and is dependent on many factors, so they may not all shut down at the same time.

5.10.2.4.2.3 System Exercise (With Load, Open, or Closed Transition Transfer)

Transfer pair control systems generally have exerciser clock functions internal to their control systems, so the exercise periods can be automatically initiated using those controls.

The transfer control system or remote device initiates an exercise period by sending start command to generator set. At the completion of the exercise period the command will be removed, allowing the system to return to normal utility service. The system operates as described above in "Normal power failure and open transition transfer return" or "Normal power failure and closed transition return", except that the system will synchronize, parallel, and ramp load to the generator bus when transferring from the utility (mains) service in closed transition transfer situations.

5.10.2.5 Multiple Transfer Pair

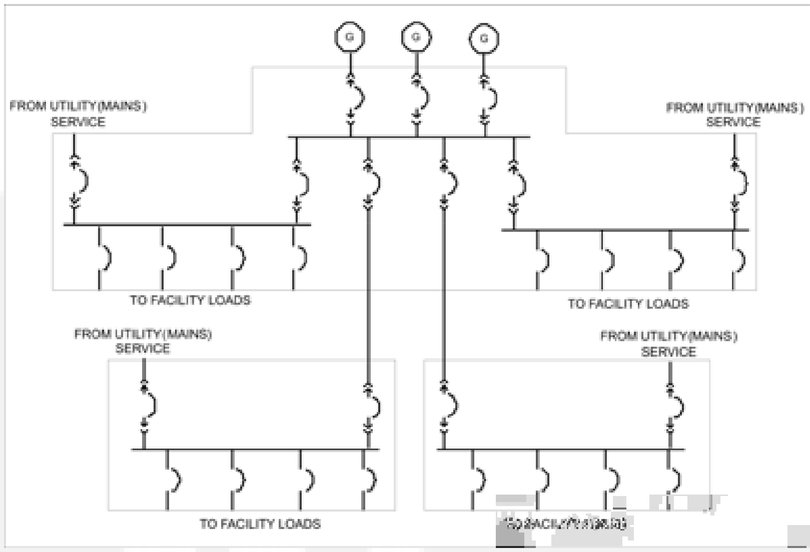

FIGURE 70. MULTIPLE TRANSFER PAIR SYSTEM WITH UTILITY MAIN/GENERATOR BUS MAIN TRANSFER PAIRS, SERVING FEEDER CIRCUIT BREAKERS.

As systems become larger, and loads exceed the steady state current capability of available circuit breakers, a common practice is to multiply the number of transfer pairs used in the application. Rather than using a single transfer pair, the power transfer functions are provided by multiple transfer pairs, in much the same fashion as the situation where a single generator set serves multiple transfer switches in a non-paralleling application.

Systems of this type are often used in medium voltage applications and in applications where an entire facility is fed generator power. These systems are often seen in interruptible power applications, cogeneration sites, or when the normal utility service is unreliable. Many data centers also use this design, or some variation of it.

Multiple transfer pair configurations are ideally suited to “soft” ramping closed transition operation, so loads can be transferred between good sources with nearly imperceptible variation in voltage and frequency of power provided to loads.

In order to maintain system reliability in the event that the power transfer system fails, each transfer pair should be provided with an auto/manual switch, breaker open/close indications, source available indications, and manual breaker control switches located close to the transfer breakers. It is also best practice to mount manual operation instructions locally to these manual control provisions, and to use an independent controller for each breaker transfer pair. Use of locally mounted independent controls reduces costs and improves reliability in much the same way a faciliity with a single generator utilizing multiple transfer switches would use an independent controller for each ATS.

5.10.2.5.1 Advantages and Disadvantages

- The primary reason for specifying a design of this type is to minimize interruptions to the load during testing of the generator sets under load and during retransfer from the emergency to the normal bus after a power failure.
- In many cases this design represents a cost-effective method of handling the system because no transfer switches are involved in the system and required on-site control wiring is extremely limited.

- This design may not be considered suitable for hospital or other critical facilities in some regions because it does not provide completely isolated life safety, critical, and equipment load services from two alternate sources which are required by some local codes and standards.
- This may be partially overcome by the addition of separate standard transfer switches for the non-equipment loads in the system, but their addition represents a compromise in the total system design concept. Another method of overcoming this problem is to provide separate normal and emergency switchgear and to use the system master processor to control the switching devices in a non-load break control system.
- Whenever circuit breakers are used for load transfer, there is a potential problem with effective ground fault protection. The neutrals of the generator sets and utility services must be connected together unless a 3-wire system is designed, or 4-pole circuit breakers or neutral contactors are used in the system. (Four-pole UL Listed power circuit breakers are not yet commonly available in North America, but they are available in other markets, designed to IEC Standards.)
- Transfer Pair Breakers used in a closed transition arrangement cannot be mechanically interlocked, so use of electrical interlocks are engaged whenever equipment is in a manual operation mode. Electrical interlocks are generally not considered to be as reliable as mechanical interlocks.

5.10.2.5.2 Sequence of Operation

Under normal conditions the transfer breaker pair connects all system loads to utility power, the generator sets are not operating and paralleling breakers are open, and the generator main breaker is open. Feeders and other distribution devices are normally closed. Feeders may be electrically operated to allow sequence of load adding and shedding. Breaker pair configurations are often designed to be configurable from open transition to closed transition. The ability to change operating sequence is useful in some cases, where utility approval of the paralleling version of the system is not available at the time of installation, but may be desirable at some future point in the system's life.

5.10.2.5.2.1 Normal Power Failure with Open Transition Retransfer

- The Transfer Control Systems (one for each utility source) independently sense failure of utility source and completes time delay start sequence. If only one transfer pair control senses a power failure, only one with transfer its loads.
- All Generator sets are commanded to start.
- Generator set (or sets) complete their individual time delay on starting (any time delay on starting that is integral to the generator set control system is typically set to zero), start, and accelerate to rated frequency and voltage. Some generator sets will start through an idle speed cycle, or start and ramp to rated speed.
- The first available generator set is selected and closes to the bus.
- All other generators synchronize to the bus and close as they reach synchronous conditions.
- The system time delay on transfer is completed, and the utility breaker opens. (The control system is generally configured to allow the utility breaker to open and initiate transfer when a predetermined number of generator sets have closed to the bus.)

- Generator bus main breaker closes and assumes connected system loads. The sequence should include an intentional time delay to allow voltage from inductive loads to decay prior to connecting an alternate source.
- As generators close to the bus, additional feeder breakers are commanded to connect to the generator bus.
- Load control system and load demand system manage system loads and capacity.
- On return of normal power the control system will initiate a time delay on retransfer to verify that utility has returned with acceptable reliability. Each transfer control system operates independently and completes the retransfer sequence described as follows when its utility source has returned.
- On completion of the time delay retransfer the generator bus main breaker opens, and after the time delay programmed transition is completed the utility breaker closes.
- On return of normal power to the second utility the control system will initiate a time delay on retransfer to verify that utility has returned with acceptable reliability.
- On completion of the time delay retransfer the generator breaker opens, and after the time delay programmed transition is completed the utility breaker closes.
- Transfer sequence repeats until all transfer pairs have returned their loads to the utility service.
- Generators operate for a cooldown cycle and shut down, ready for another command to start. The cooldown cycle is typically programmed into each generator set controller and is dependent on many factors, so they may not all shut down at the same time.

5.10.2.5.2.2 Normal Power Failure and Closed Transition Return

- The Transfer Control Systems (one for each utility source) independently sense failure of utility source and completes time delay start sequence. If only one transfer pair control senses a power failure, only one with transfer its loads.
- All Generator sets are commanded to start.
- Generator set (or sets) complete their individual time delay on starting (any time delay on starting that is integral to the generator set control system is typically set to zero), start, and accelerate to rated frequency and voltage. Some generator sets will start through an idle speed cycle, or start and ramp to rated speed.
- The first available generator set is selected and closes to the bus.
- All other generators synchronize to the bus and close as they reach synchronous conditions.
- The system time delay on transfer is completed, and the utility breaker opens. (The control system is generally configured to allow the utility breaker to open and initiate transfer when a predetermined number of generator sets have closed to the bus.)
- Generator bus main breaker closes and assumes connected system loads. The sequence should include an intentional time delay to allow voltage from inductive loads to decay prior to connecting an alternate source.
- As generators close to the bus, additional feeder breakers are commanded to connect to the generator bus.
- Load control system and load demand system manage system loads and capacity.

- On return of normal power the control system will initiate a time delay on retransfer to verify that utility has returned with acceptable reliability. Each transfer control system operates independently and completes the retransfer sequence described as follows when its utility source has returned.
- On completion of the time delay retransfer the system will verify synchronization of the generator set bus with the utility service, and then close the utility breaker, paralleling the generator sets with the utility service.
- The system ramps generator bus load to zero load, and on reaching the programmed minimum power condition the generator bus breaker will open.
- Generator sets will continue to operate in parallel as long as any breaker pair has not retransferred to the utility service.
- On return of normal power to other utility service points the control system will initiate a time delay on retransfer to verify that utility has returned with acceptable reliability. The system will synchronize the generator set bus output to the utility when the utility source is sensed to be good.
- On completion of the time delay retransfer the system will verify synchronization of the generator set bus with the utility service, and then close the utility breaker, paralleling the generator sets with the utility service.
- The system ramps generator bus load to zero load, and on reaching the programmed minimum power condition the generator bus breaker will open.
- When all loads are transferred back to the utility service, the generators operate for a cooldown cycle and shut down, ready for another command to start. The cooldown cycle is typically programmed into each generator set controller and is dependent on many factors, so they may not all shut down at the same time.

5.10.2.5.2.3 System Exercise (With Load, Open, or Closed Transition Transfer)

- Transfer pair control systems commonly include an exerciser clock, which can be programmed to initiate system exercise at pre-programmed times. The system also may be commanded to exercise mode from an external control system. Operation is the same regardless of where the exercise command is issued.
- The transfer control system or remote device initiates an exercise period by sending start command to generator set. At the completion of the exercise period the command will be removed, allowing the system to return to normal utility service.
- The system operates as described above in "Normal power failure and open transition transfer return" or "Normal power failure and closed transition return".

5.10.2.6 Common Bus Systems

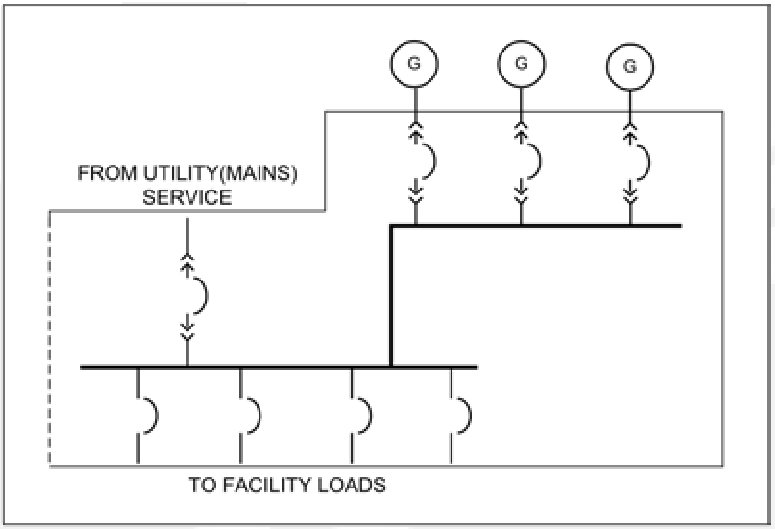

FIGURE 71. COMMON BUS SYSTEM WITH UTILITY MAIN BREAKER ON COMMON BUS WITH GENERATOR PARALLELING BREAKERS, SERVING FEEDER CIRCUIT BREAKERS.

A common bus system has the same design as a transfer pair configuration, except that the generator bus main breaker is eliminated, mostly for the purpose of reducing the cost of the system.

5.10.2.6.1 Advantages and Disadvantages

- Where the local utility service provider allows paralleling of the generator bus to the utility service for at least 10 seconds, the system provides a means to transfer loads to the generator bus and back to the utility without disrupting operation of sensitive loads.
- Since the system power transfer functions are provided within the system design, it is often one of the less expensive ways to provide a factory built and fully assembled system, since it doesn’t require transfer switches which would require more field wiring.
- All loads are served by two sources, so there is inherent redundancy of service in the system. If one service fails, the other automatically takes over.
- A major disadvantage versus breaker transfer pair configuration is the reduction in serviceability. Since the generator sets are connected on a common bus with the utility service, it is not possible to service the paralleling controls or test the generator set with facility loads without disrupting power to the facility. This is a huge disadvantage, especially when it is considered that the only advantage is avoiding the cost of the generator bus main breaker in the system.
- Not commonly used on smaller systems (rated less than 800 amps steady state), because of the service difficulty and durability of most molded case breakers.
- Ground fault protection can be incorporated to the system, but will malfunction when 3-pole switching is used. When ground fault is required, either 4-pole switching should be used, the ground fault protection should be moved to downstream to feeder breakers, or an alternate ground fault protection scheme should be used.
- Load management is generally accomplished with electrically operated feeder breakers.

- For U.S. applications where Emergency and Legally Required loads are served from the generator system, these loads must be physically isolated from Optional Standby loads. Consequently, this design should not be used in North America applications where the equipment is required to serve both emergency or legally required, and optional standby loads.

5.10.2.6.2 Sequence of Operation

Under normal conditions a utility main breaker connects all system loads to utility power, and the generator sets are not operating and paralleling breakers are open. Feeders and other distribution devices are normally closed. Feeders may be electrically operated to allow sequence of load adding and shedding. Common bus configurations are often designed to be configurable from open transition to closed transition (100 millisecond closed transition is not possible). The ability to change operating sequence is useful in some cases, where utility approval of the paralleling version of the system is not available at the time of installation, but may be desirable at some future point in the system's life.

5.10.2.6.2.1 Normal Power Failure with Open Transition Retransfer

- The Transfer Control System senses failure of the utility source and completes time delay start sequence.
- All Generator sets are commanded to start.
- Generator set (sets) complete their individual time delay on starting (any time delay on starting that is integral to the generator set control system is typically set to zero), start, and accelerate to rated frequency and voltage. Some generator sets will start through an idle speed cycle, or start and ramp to rated speed.
- When at least one generator set is ready to close to the bus, the utility main breaker will be opened. (System is configurable to command main breaker opening based on availability of a specific number of generator sets.)
- All priority 2 and lower feeder breakers are opened.
- The system selects an available generator set and it is allowed to close to the bus. First priority loads are automatically served.
- All other generators synchronize to the bus and close as they reach synchronous conditions.
- Generators begin load sharing and ramp to the same percent of load after they are individually closed to the bus.
- As generators close to the bus, additional feeder breakers are commanded to connect to the generator bus.
- Load control system and load demand system manage system loads and capacity.
- On return of normal power the control system will initiate a time delay on retransfer to verify that utility has returned with acceptable reliability.
- On completion of the time delay retransfer the generator paralleling breakers all open, and after the time delay programmed transition is completed the utility breaker closes.
- Generators operate for a cooldown cycle and shut down, ready for another command to start. The cooldown cycle is typically programmed into each generator set controller and is dependent on many factors, so they may not all shut down at the same time.

5.10.2.6.2.2 Normal Power Failure with Closed Transition Retransfer

- The Transfer Control System senses failure of the utility source and completes time delay start sequence.
- All Generator sets are commanded to start.
- Generator set (or sets) complete their individual time delay on starting (any time delay on starting that is integral to the generator set control system is typically set to zero), start, and accelerate to rated frequency and voltage. Some generator sets will start through an idle speed cycle, or start and ramp to rated speed.
- When at least one generator set is ready to close to the bus, the utility main breaker will be opened. (System is configurable to command main breaker opening based on availability of a specific number of generator sets.)
- All priority 2 and lower feeder breakers are opened.
- The system selects an available generator set and it is allowed to close to the bus. First priority loads are automatically served.
- All other generators synchronize to the bus and close as they reach synchronous conditions.
- Generators begin load sharing and ramp to the same percent of load after they are individually closed to the bus.
- As generators close to the bus, additional feeder breakers are commanded to connect to the generator bus.
- Load control system and load demand system manage system loads and capacity.
- On return of normal power the control system will initiate a time delay on retransfer to verify that utility has returned with acceptable reliability.
- On completion of the time delay retransfer the system will verify synchronization of the generator set bus with the utility service, and then close the utility breaker, paralleling the generator sets with the utility service.
- The system ramps generator bus load to zero load, and on reaching the programmed minimum power condition the generator paralleling breakers will open.
- Generators operate for a cooldown cycle and shut down, ready for another command to start. The cooldown cycle is typically programmed into each generator set controller and is dependent on many factors, so they may not all shut down at the same time.

5.10.2.6.2.3 System Exercise (with Load, Open, or Closed Transition)

- Common bus control systems commonly include an exerciser clock, which can be programmed to initiate system exercise at pre-programmed times. The system also may be commanded to exercise mode from an external control system. Operation is the same regardless of where the exercise command is issued.
- The transfer control system or remote device initiates an exercise period by sending start command to generator set. At the completion of the exercise period the command will be removed, allowing the system to return to normal utility service.
- The system operates as described above in "Normal power failure and open transition transfer return" or "Normal power failure and closed transition return".

5.10.2.7 Main/Tie/Main Systems

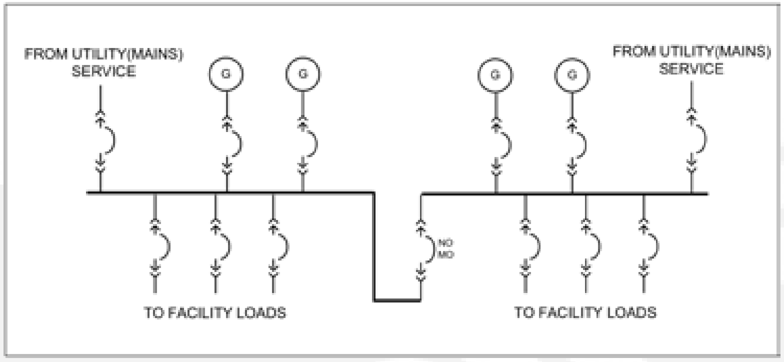

FIGURE 72. MAIN-TIE-MAIN CONFIGURATIONS SERVING FEEDER CIRCUIT BREAKERS. NOTE THAT THE DESIGN IS SIMILAR TO A DUAL COMMON BUS ARRANGEMENT, WITH A NORMALLY OPEN TIE.

Main-Tie-Main configurations are very common in industrial facilities around the world, and it is commonplace to simply add generator sets to the two primary system buses to accommodate system expansion. In systems where the individual utility transformers are sized to take on the entire facility load, in the event of one utility service failing, the tie breaker will close and the live utility service will feed the entire facility. In such an application the generators only come on line if both utility services fail.

5.10.2.7.1 Advantages and Disadvantages

- Where the local utility service provider allows paralleling of the generator bus to the utility service for at least 10 seconds, the system provides a means to transfer loads to the generator bus and back to the utility without disrupting operation of sensitive loads.
- Since the system power transfer functions are provided within the system design, it is often one of the less expensive ways to provide a factory built and fully assembled system, since it doesn’t require transfer switches which would require more field wiring.
- All loads are served by two sources, so there is inherent redundancy of service in the system. If one service fails, the other automatically takes over.
- A major disadvantage versus breaker transfer pair configuration is the reduction in serviceability. Since the generator sets are connected on a common bus with the utility service, it is not possible to service the paralleling controls or test the generator set with facility loads without disrupting power to the facility. This is a huge disadvantage, especially when it is considered that the only advantage is avoiding the cost of the generator bus main breaker in the system.
- Not commonly used on smaller systems (rated less than 800 amps steady state), because of the service difficulty and durability of most molded case breakers.
- Ground fault protection can be incorporated to the system, but will malfunction when 3-pole switching is used. When ground fault is required, either 4-pole switching should be used, the ground fault protection should be moved to downstream to feeder breakers, or an alternate ground fault protection scheme should be used.

- Load management is generally accomplished with electrically operated feeder breakers.
- For U.S. applications where emergency and legally-required loads are served from the generator system, these loads must be physically isolated from optional standby loads. Consequently, this design should not be used in North American applications where the equipment is required to serve both emergency or legally-required and optional standby loads.
- The specification of the sequence of operation requires attention to details of operation of the tie breaker when the tie breaker is electrically operated, because several different sequences are possible. Because the generators of each bus may or may not load share with each other, the load sharing system must be designed to work in multiple modes. These issues complicate the design and service of the equipment over the life of the system.

5.10.2.7.2 Sequence of Operation

5.10.2.7.2.1 Normal Power Failure with Open Transition Retransfer

- The Transfer Control Systems (one for each utility source) independently sense failure of utility source and completes time delay start sequence. If only one transfer control senses a power failure, only one will transfer its loads.
- All Generator sets on the affected bus are commanded to start.
- Generator set (or sets) complete their individual time delay on starting (any time delay on starting that is integral to the generator set control system is typically set to zero), start, and accelerate to rated frequency and voltage. Some generator sets will start through an idle speed cycle, or start and ramp to rated speed.
- When at least one generator set is ready to close to the bus, the utility main breaker will be opened. (System is configurable to command main breaker opening based on availability of a specific number of generator sets.)
- All priority 2 and lower feeder breakers are opened.
- The system selects an available generator set and it is allowed to close to the bus. First priority loads are automatically served.
- All other generators synchronize to the bus and close as they reach synchronous conditions.
- As generators close to the bus, additional feeder breakers are commanded to connect to the generator bus.
- Load control system and load demand system manage system loads and capacity.
- On return of normal power the control system will initiate a time delay on retransfer to verify that utility has returned with acceptable reliability. Each transfer control system operates independently and completes the retransfer sequence described as follows when its utility source has returned.
- On completion of the time delay retransfer the generator paralleling breakers on the bus to be transferred all open, and after the time delay programmed transition is completed the utility breaker closes.
- Generators associated with the utility in service operate for a cooldown cycle and shut down, ready for another command to start. The cooldown cycle is typically programmed into each generator set controller and is dependent on many factors, so they may not all shut down at the same time.

- On return of normal power to the second utility the control system will initiate a time delay on retransfer to verify that utility has returned with acceptable reliability.
- On completion of the time delay retransfer the generator paralleling breakers open, and after the time delay programmed transition is completed the utility breaker closes.
- Generators operate for a cooldown cycle and shut down, ready for another command to start. The cooldown cycle is typically programmed into each generator set controller and is dependent on many factors, so they may not all shut down at the same time.

5.10.2.7.2.2 Normal Power Failure and Closed Transition Return

- The Transfer Control Systems (one for each utility source) independently sense failure of utility source and completes time delay start sequence. If only one transfer pair control senses a power failure, only one will transfer its loads.
- All Generator sets are commanded to start.
- Generator set (or sets) complete their individual time delay on starting (any time delay on starting that is integral to the generator set control system is typically set to zero), start, and accelerate to rated frequency and voltage. Some generator sets will start through an idle speed cycle, or start and ramp to rated speed.
- When at least one generator set is ready to close to the bus, the utility main breaker will be opened. (System is configurable to command main breaker opening based on availability of a specific number of generator sets.)
- All priority 2 and lower feeder breakers are opened.
- The system selects an available generator set and it is allowed to close to the bus. First priority loads are automatically served.
- All other generators synchronize to the bus and close as they reach synchronous conditions.
- As generators close to the bus, additional feeder breakers are commanded to connect to the generator bus.
- Load control system and load demand system manage system loads and capacity.
- On return of normal power the control system will initiate a time delay on retransfer to verify that utility has returned with acceptable reliability. The system will synchronize the generator set bus output to the utility when the utility source is sensed to be good. The system can only synchronize to one source at a time, so synchronizing will occur first at the first available source, and then at the second.
- On completion of the time delay retransfer the system will verify synchronization of the generator set bus with the utility service, and then close the utility breaker, paralleling the generator sets with the utility service.
- The system ramps generator bus load to near zero load, and on reaching the programmed minimum power condition the generator paralleling breakers associated with the transferred loads will open.
- Generators associated with the transferred loads operate for a cooldown cycle and shut down, ready for another command to start. The cooldown cycle is typically programmed into each generator set controller and is dependent on many factors, so they may not all shut down at the same time.
- Generator sets will continue to operate in parallel as long as any breaker pair has not retransferred to the utility service.

- On return of normal power to the second utility service the control system will initiate a time delay on retransfer to verify that utility has returned with acceptable reliability. The system will synchronize the generator set bus output to the utility when the utility source is sensed to be good.
- On completion of the time delay retransfer the system will verify synchronization of the generator set bus with the utility service, and then close the utility breaker, paralleling the generator sets with the utility service.
- The system ramps generator bus load to zero load, and on reaching the programmed minimum power condition the generator paralleling breakers will open.
- Generators operate for a cooldown cycle and shut down, ready for another command to start. The cooldown cycle is typically programmed into each generator set controller and is dependent on many factors, so they may not all shut down at the same time.

5.10.2.7.2.3 System Exercise (With Load, Open, or Closed Transition)

- Main-Tie-Main control systems commonly include an exerciser clock, which can be programmed to initiate system exercise at pre-programmed times. The system also may be commanded to exercise mode from an external control system. Operation is the same regardless of where the exercise command is issued.
- The transfer control system or remote device initiates an exercise period by sending start command to generator set. At the completion of the exercise period the command will be removed, allowing the system to return to normal utility service.
- The system operates as described above in "Normal power failure and open transition transfer return" or "Normal power failure and closed transition return".

5.10.2.8 Main Tie Main With Common Generator Bus

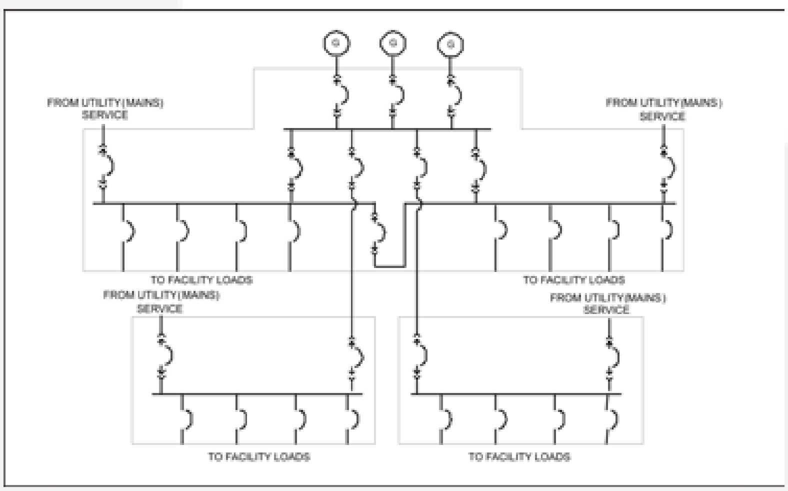

FIGURE 73. MAIN-TIE-MAIN WITH COMMON GENERATOR BUS.

In the figure above, note that the system design requires only one more breaker to implement, and it resolves the important deficiencies of the main-tie-main design. The tie breaker is often manually operated, since it is only used for service functions.

A very common variation on the traditional main-tie-main system is the system shown in the figure above. The system advantages and disadvantages and sequence of operation are similar to the transfer pair configuration, but the system has the added advantage of allowing the utility services to support one another for service/maintenance purposes without energizing the generator bus.

The system control design is more complex than the transfer pair design when the tie breaker is automated. Since many facilities are fed by a single utility service, failure of service to only one of the transfer pairs is not a common event, so “nuisance” starting of the generator system is not considered to be a significant problem. The tie breaker is typically used as a maintenance device only.

The sequence of operation for a system with a manually operated tie is nearly identical to the operation of the multiple transfer pair operation. The only difference being that if the tie is closed, the non-operational utility source is locked out.

The following sequence can be used when the tie is automated.

5.10.2.8.1 Sequence of Operation

5.10.2.8.1.1 Failure of a Single Utility/Mains Source and Open Transition Return

- The Transfer Control Systems (one for each utility source) independently sense failure of utility source and completes time delay start sequence.
- The utility source breaker opens, and after a short time programmable time delay the tie breaker closes, connecting the system loads to the alternate utility source.
- On return of the utility service, and after a time delay on retransfer is completed, the tie breaker opens, after a short time programmable time delay the utility breaker closes, connecting the system loads to the normal utility source.

5.10.2.8.1.2 Failure of a Single Utility/Mains Source and Closed Transition Return

- The Transfer Control Systems (one for each utility source) independently sense failure of utility source and completes time delay transfer sequence.
- The utility source breaker opens, and after a short time programmable time delay the tie breaker closes, connecting the system loads to the alternate utility source.
- On return of normal power the control system will initiate a time delay on retransfer to verify that utility has returned with acceptable reliability.
- The system will verify synchronization of the utility services, and then close the open utility breaker, paralleling the two utility services.
- The system will immediately open the tie breaker, isolating the utility services from one another. (The utility services will be paralleled for 100 ms or less.)

5.10.2.8.1.3 Normal Power Failure with Open Transition Retransfer

- The Transfer Control Systems (one for each utility source) independently sense failure of utility source and completes time delay start sequence.
- All Generator sets are commanded to start.
- Generator set (or sets) complete their individual time delay on starting (any time delay on starting that is integral to the generator set control system is typically set to zero), start, and accelerate to rated frequency and voltage. Some generator sets will start through an idle speed cycle, or start and ramp to rated speed.

- When at least one generator set is ready to close to the bus, the utility main breaker will be opened. (System is configurable to command main breaker opening based on availability of a specific number of generator sets.)
- All priority 2 and lower feeder breakers are opened.
- The system selects an available generator set and it is allowed to close to the bus. First priority loads are automatically served.
- All other generators synchronize to the bus and close as they reach synchronous conditions.
- As generators close to the bus, additional feeder breakers are commanded to connect to the generator bus.
- Load control system and load demand system manage system loads and capacity.
- On return of normal power the control system will initiate a time delay on retransfer to verify that utility has returned with acceptable reliability. Each transfer control system operates independently and completes the retransfer sequence described as follows when its utility source has returned. (The system manages the transition initiation so that only one utility service retransfers at a time.)
- On completion of the time delay retransfer the generator paralleling breakers on the bus to be transferred all open, and after the time delay programmed transition is completed the utility breaker closes.
- Generators associated with the utility in service operate for a cooldown cycle and shut down, ready for another command to start. The cooldown cycle is typically programmed into each generator set controller and is dependent on many factors, so they may not all shut down at the same time.
- On return of normal power to the second utility the control system will initiate a time delay on retransfer to verify that utility has returned with acceptable reliability.
- On completion of the time delay retransfer the generator paralleling breakers open, and after the time delay programmed transition is completed the utility breaker closes.
- Generators operate for a cooldown cycle and shut down, ready for another command to start. The cooldown cycle is typically programmed into each generator set controller and is dependent on many factors, so they may not all shut down at the same time.

5.10.2.8.1.4 Normal Power Failure with Closed Transition Retransfer

- The Transfer Control Systems (one for each utility source) independently sense failure of utility source and completes time delay start sequence. If only one transfer pair control senses a power failure, only one with transfer its loads.
- All Generator sets are commanded to start.
- Generator set (or sets) complete their individual time delay on starting (any time delay on starting that is integral to the generator set control system is typically set to zero), start, and accelerate to rated frequency and voltage. Some generator sets will start through an idle speed cycle, or start and ramp to rated speed.
- When at least one generator set is ready to close to the bus, the utility main breaker (or breakers) will be opened. (System is configurable to command main breaker opening based on availability of a specific number of generator sets.)
- All priority 2 and lower feeder breakers are opened.

- The system selects an available generator set and it is allowed to close to the bus. First priority loads are automatically served.
- All other generators synchronize to the bus and close as they reach synchronous conditions.
- As generators close to the bus, additional feeder breakers are commanded to connect to the generator bus.
- Load control system and load demand system manage system loads and capacity.
- On return of normal power the control system will initiate a time delay on retransfer to verify that utility has returned with acceptable reliability. The system will synchronize the generator set bus output to the utility when the utility source is sensed to be good. The system can only synchronize to one source at a time, so synchronizing will occur first at the first available source, and then at the second.
- On completion of the time delay retransfer the system will verify synchronization of the generator set bus with the utility service, and then close the utility breaker, paralleling the generator sets with the utility service.
- The system ramps generator bus load to near zero load, and on reaching the programmed minimum power condition the generator paralleling breakers associated with the transferred loads will open.
- Generators associated with the transferred loads operate for a cooldown cycle and shut down, ready for another command to start. The cooldown cycle is typically programmed into each generator set controller and is dependent on many factors, so they may not all shut down at the same time.
- Generator sets will continue to operate in parallel as long as any breaker pair has not retransferred to the utility service.
- On return of normal power to the second utility service the control system will initiate a time delay on retransfer to verify that utility has returned with acceptable reliability. The system will synchronize the generator set bus output to the utility when the utility source is sensed to be good.
- On completion of the time delay retransfer the system will verify synchronization of the generator set bus with the utility service, and then close the utility breaker, paralleling the generator sets with the utility service.
- The system ramps generator bus load to zero load, and on reaching the programmed minimum power condition the generator paralleling breakers will open.
- Generators operate for a cooldown cycle and shut down, ready for another command to start. The cooldown cycle is typically programmed into each generator set controller and is dependent on many factors, so they may not all shut down at the same time.

5.10.2.8.1.5 System Exercise (With Load, Open, or Closed Transition)

- Main-Tie-Main control systems commonly include an exerciser clock, which can be programmed to initiate system exercise at pre-programmed times. The system also may be commanded to exercise mode from an external control system. Operation is the same regardless of where the exercise command is issued.
- The transfer control system or remote device initiates an exercise period by sending start command to generator set. At the completion of the exercise period the command will be removed, allowing the system to return to normal utility service.

- The system operates as described above in "Normal power failure and open transition transfer return" or "Normal power failure and closed transition return", except that in the closed transition mode the generators sets start, synchronize, and close to the common bus, then they are synchronized to the utility, closed, and load is ramped to the oncoming source, both on start and completion of the exercise period.

6 Equipment Protection

6.1 Overview

This section covers system failure modes, and what provisions can be instilled into a system to minimize the effect of common failures. Concepts of design for enhanced reliability will be discussed and reviewed. Protection of the generator set, loads and the overall system is discussed as it relates to emergency/paralleling systems versus utility distribution prime power/rental systems. Failure modes and mitigation related to sequence of operation is also discussed in Section 4-On-Site System Design Considerations. Protection measures for utility/mains paralleling systems are also covered in **Section 7.5.1.3 on page 234**.

The protective devices and settings selected for a specific application should always be selected based on an understanding of the optimum balance between reliability and protection. The more protection used in the system the lower the reliability, because of the higher probability of failing the system due to a nuisance trip. In general, we find that normal distribution systems, prime power systems, and other equipment that operates continuously will commonly have comprehensive protective arrangements. In emergency, or highly critical standby applications (such as data centers), the perspective begins to shift. In critical situations (i.e., where normal power has already failed) many users might rather risk the equipment rather than endure a certain facility failure. If a generator set is running in an emergency, the last thing a user needs is a shutdown because something MIGHT be wrong.

Another significant difference in emergency standby versus normal source distribution system equipment is that emergency equipment is rarely in service. Normal distribution has a higher probability of having a fault, simply because it is commonly operating 24-hours per day.

This document does not cover protection of the equipment in the distribution system of a paralleling application. It is recommended that the reader look to other sources such as those published by IEEE and IEC, as well as protective relaying equipment manufacturers for more information on this topic.

6.2 Requirements and Recommendations

6.2.1 Requirements

- The protective devices and settings selected for a specific application should always be selected based on a proper balance between reliability and protection. Emergency/Standby systems need more reliability and prime power/rental systems typically need more protection.
- Generator set protection in paralleling applications must include overcurrent (both overload and external short circuit), reverse power (kW) and reverse kVAR functions.
- Generator set protection and settings must be selected based on the specific characteristics of the equipment used, which will be different than settings used for the same functions in utility/mains circuits.
- Protect loads with the same considerations as you would use for utility/mains powered systems, but remember the limitations of the generator system, also.

- Utility/mains intertied systems require protection for the interconnection. This protection is generally specified by the utility/mains supplier to a facility, and must be selected based on the characteristics and needs of the utility/mains distribution system.

6.2.2 Recommendations

- Protective relay type should be selected based on the criticality of the installation. Critical protection should be done with “utility grade” devices.
- Engine protection functions for engines with analog sensors should be field tested using control simulations, rather than by actually testing the sensor and control system separately.
- When a generator-mounted main disconnect or circuit breaker is used with a downstream paralleling breaker, the paralleling breaker should always be automatically opened when the main disconnect or breaker is opened.
- AC protective devices that are generator set mounted should be prototype tested to verify acceptable performance in the harsh mechanical conditions surrounding a generator set application.
- Ground/earth fault protection should not be used on generator sets that are paralleled. Primary ground/earth fault protection should be “downstream” from the paralleling bus.
- Evaluate your *system design* for single points of failure, and decide on the best action for the system under consideration for each failure point: design it out, add true redundancy, or specify best possible reliability for the critical equipment or function.
- Whenever conductors leave a switchboard/switchgear or generator source, they should be protected for the potential effects of both overloads and short circuits.

6.3 General Considerations for Protection

The type and functions of protective relaying specified for a facility is affected by type of application. Generator set-powered systems for emergency/standby applications should be optimized for reliability while utility-served and prime power applications are often optimized for protection of equipment. This means emergency/standby generator systems will often have fewer protective devices and less stringent settings than some other systems.

In a paralleling system, since there are multiple sources of power there are multiple strategies to put into place in order to optimally protect various parts of the system, particularly in emergency/standby applications.

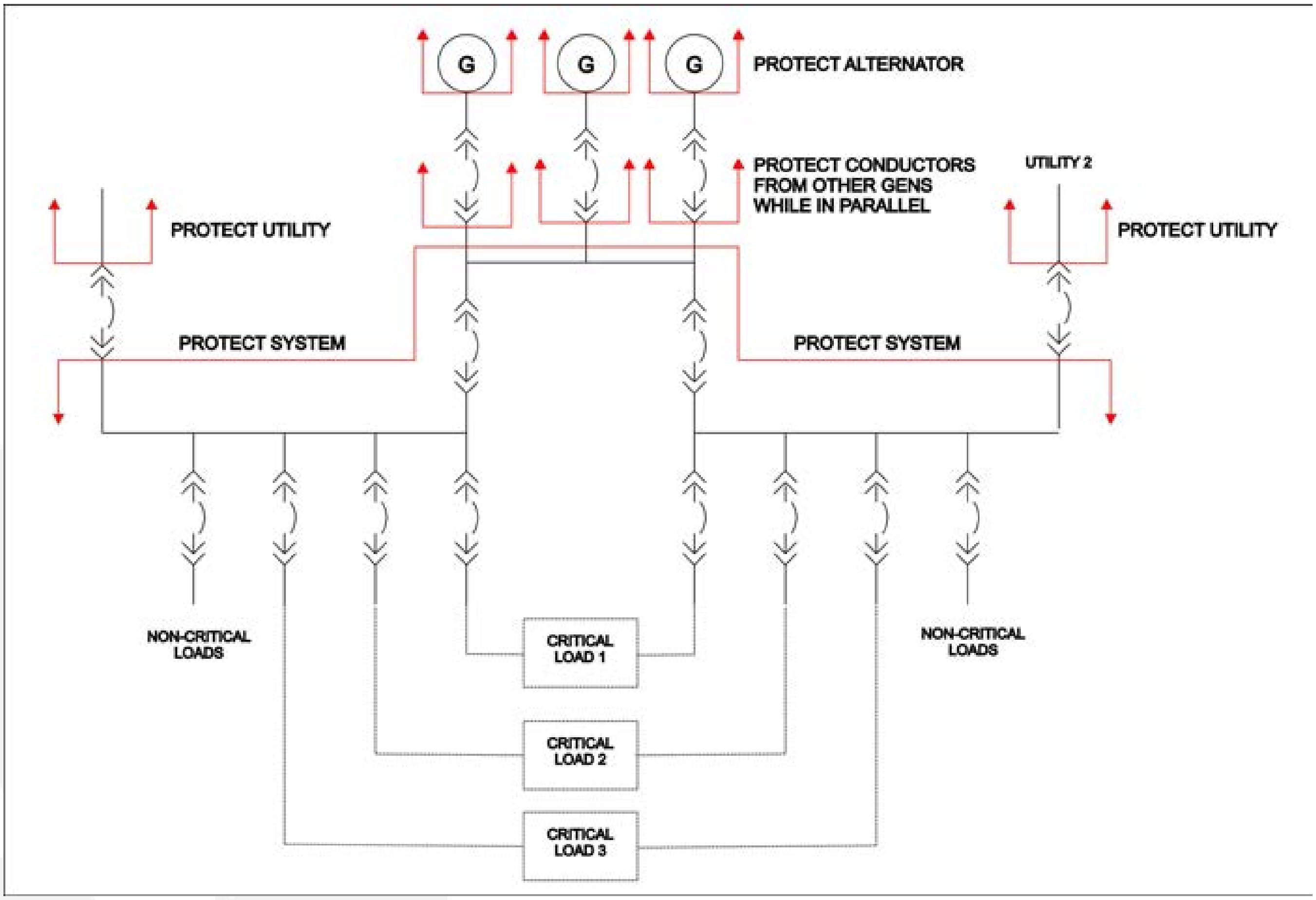

FIGURE 74. MULTIPLE POWER SOURCES MEANS MULTIPLE PROTECTION STRATEGIES.

On site power systems have four distinctly different groups of equipment to protect, and each group requires a strategy of protection that is appropriate for the application.

- For generator sets in paralleling applications, the primary AC protection that is required is overload protection, reverse kW, and reverse kVAR. More information on generator set protection is in Section 3.4.5 on page 34. Engines must also be protected. The exact protection required is impacted by local codes and standards, as well as manufacturer requirements. Consider also the level of protection required to retain system reliability.
- The loads connected to the on-site power system require protection from the effects of over voltage and serious frequency variation. In addition, systems often incorporate ground (earth) fault protection. Some loads, such as motor loads require protection against sustained under voltage conditions.
- Distribution equipment requires protection from the impacts of overcurrent and short circuit conditions.
- When systems incorporate grid interconnection, protection for the utility (mains) service is required. These functions vary with the application and with utility requirements, but often include over/under voltage and frequency, and reverse power. Vector shift and/or rate of change of frequency protection is also useful in quicklly detecting the loss of the utility source when operating generator sets in parallel with the utility/mains services.

In each of these subgroups, protection functions and settings are made based on the type and level of protection that is appropriate to the application, while having minimum impact on system reliability.

6.4 AC Protection Relay Types

Protective relaying equipment is available in different quality/performance or grade levels. Two common types are:

- Industrial grade equipment is typically solid state, and is fixed-mounted inside a switchboard or control cabinet. Industrial grade equipment is relatively inexpensive, and limited in function, adjustability, and accuracy.
- Utility grade equipment may be either electromechanical or solid state/microprocessor-based devices. While there is not a formal 3rd party approval process to designate “utility grade” equipment, distinguishing features in utility grade versus industrial grade equipment are: better measurement accuracy, provisions for testing the relay while in service, considerably better voltage surge withstand ability, and RFI/EMI capability as demonstrated by compliance to various international standards, and a broad range of adjustability.

Utility grade equipment is much more expensive (up to 10 times the cost of industrial grade equipment), but is often provided with test facilities such as door-mounted draw out enclosures. Many features and adjustment ranges are available with utility grade equipment. Solid state/microprocessor-based equipment is typically provided, because it offers more flexibility and requires less maintenance than electromechanical equipment.

The specific relaying chosen for any application is a function of the nature of the application, the value of the equipment being protected, and how critical the process or facility is expected to be. For example, low voltage generators are often protected with industrial grade equipment (when they are in less critical applications); but utility service protection and medium voltage generators are commonly provided with utility grade protective devices because of the higher replacement cost and impact of sustained service loss in that equipment. Protective functions are also selected based on a careful understanding of the balance necessary between reliability of service and protection of equipment.

6.5 Generator Set Protection in Paralleling Applications

Generator sets are expensive capital equipment and designers are often concerned with protecting the investment of the equipment owner in this equipment. However, in selecting and specifying generator set protection systems, it is important to recognize several factors:

- Generator sets are devices that have different characteristics from a utility service, and often must be protected in different ways than the balance of the distribution system by using different devices, functions or settings than would be used for protection of a utility service.
- In addition to the electrical protection of the alternator and control systems, it is critical that the engine protection is properly considered, especially in light of the availability of microprocessor-based control systems that can provide improved reliability versus more traditional designs that use sensing switches to drive protection operations.

- Protection is inversely related to reliability. As more protection is added to the system for generator set protection, the probability of unnecessary shutdown of the equipment increases. Redundant protective devices will make the system less reliable, so generally should not be used in emergency/standby applications.
- In emergency and standby applications, it should be recognized that the generator sets are in place for protection of critical equipment or processes, or human life. Consequently, it may be appropriate to expose the owner to a higher probability of equipment loss in order to reduce the probability of a nuisance protective system operation. Conversely, generator sets in prime power or temporary applications will generally be applied with more stringent protective systems, since damage from external problems could result in long duration power problems in a facility.

The electrical inspector (authority having jurisdiction) responsible for a site will generally require a review of the protection and settings for a site and approve the overall protection scheme.

6.5.1 Engine Protection

Some codes and standards, such as NFPA 110 in the USA and CSA 282 in Canada require that generator sets in critical applications be provided with specific protective devices. In addition, it is often necessary for the supplier of a generator set in a critical application to verify that the engine protective functions are operational at commissioning and at regular intervals thereafter.

Traditionally the engine protective functions were simply verified to be functional by inducing a fault with the specific sensor and noting that the engine provided the appropriate alarm on its control panel and shut down the engine when required. In situations where greater verification was required, the installation of the sensor on the generator set was required to be modified to demonstrate that the sensor actually sensed an accurate temperature and shut down the generator set when required. For example, the high engine temperature sensor could be removed from the engine (with the normal sensor location plugged, and the sensor inserted into a fluid with a known temperature that would cause and alarm or shutdown condition.

These traditional tests were done (and many current requirements in codes and standards) assuming that the sensor itself was a simple switching device that either opened or closed when improper conditions are present. Many standards and test practices have not been updated to consider how best to deal with analog sensors now commonly used on many engines, particularly those that incorporate advanced emission control capabilities.

In an analog sensor, the device produces a specific electrical output that varies with the value of the temperature or pressure sensed. For example, an oil pressure sensor may have a normal operating range of one to five volts for oil pressure of magnitude of 0 to 100 PSI (pounds per square inch). The control system senses this value and uses it for display of actual conditions, and also uses the value sensed to provide the control functions for logical protection of the engine.

In contrast to the traditional switching sensor system, the analog sensor displays the value of the condition sensed, so an operator can detect whether the sensor is functioning properly based on known normal conditions in the engine. Furthermore, most control systems using analog sensors are programmed to detect abnormal sensor levels (such as less than 1 volt or more than 5 volts in the previous example) and annunciate them as *sensor failure* or *circuit failure* conditions. In other words, because the control itself knows what the normal range of acceptable values are, the control can detect the failure or a sensor or the circuit between the control and the sensor, and sound an alarm describing a sensor failure or a circuit failure rather than immediately shutting down a generator set.

This provides several advantages versus traditional switching type sensors when a qualified quality control system (such as ISO 9000 series processes) are used in manufacturing plants:

- The sensor itself is verified by a quality process at the source plant, and can be verified by random testing at the generator set manufacturer. It is also verified to be operational if it, coupled with the monitoring and control system on the generator set, displays an appropriate temperature during normal testing.
- The sensor is monitored through the life of the generator set simply by displaying an appropriate temperature at all times, and a sensor failure is easily detected.
- A sensor or circuit failure need not cause a shutdown of the generator set in a critical application, because the control system will detect the difference between a sensor failure and an actual engine failure condition.

It is also worth noting that when the generator set control system is provided with analog sensor systems, testing of the shut down circuit should be demonstrated with simulations driven by the control system (such as changing acceptance limits of the protection) rather than taking heroic measures that have been historically required in order to force the control system to indicate an actual failure on an operational engine. Field testing of sensors and associated circuits can introduce failure conditions into a generator set unnecessarily.

More information on engine protection systems is available in Cummins Manual T-030, the generator set application manual.

6.5.1.1 Low Lube Oil Pressure/High Engine Temperature

Low lube oil pressure or high engine temperature (in liquid-cooled engines this is high coolant temperature) will ultimately result in severe engine damage, so this protection function is critical in all engines, particularly in emergency/standby applications where they are often operating unattended. The specific pressures and temperatures that are used for protective settings should be specified by the engine manufacturer.

6.5.1.2 Fail to Start (Overcrank)/Fail to Crank

These two conditions can occur when the engine will not start and when the engine does not rotate when the command to start occurs. When the generator set can identify this as a separate fault, it aids in the faster analysis of a failure of the system to come on line. The Fail to Crank and Fail to Start functions are performed by monitoring the engine flywheel magnetic pickup that is used to sense engine speed. If the engine attempts a start and it does not rotate, a “Fail to Crank” shutdown condition is indicated. If the engine rotates but does not start, a “Fail to Start” shutdown is indicated. In general, multiple attempts to crank and start are attempted before the alarm is issued and the machine locked out.

6.5.1.3 Overspeed

Overspeed shutdown occurs when the engine rotational speed exceeds a safe level. Since speed is directly proportional to frequency, the Overspeed and over frequency shutdown conditions should be coordinated. Since damage occurs over some time period, it is reasonable to have an inverse characteristic in this function, so that safe Overspeed for a short time is allowed, but unsafe levels are avoided. Like the fail to start or crank alarms, this function uses speed sensing from the magnetic pickup on the engine in order to sense the failure condition and shut down the engine.

6.5.1.4 Low Coolant Level

Coolant temperature sensors generally cannot sense engine temperature unless they are immersed in coolant. So, if the engine coolant system ruptures and leaves the engine running without coolant, a high engine temperature cannot be sensed and the engine will run to destruction. Consequently, most generator sets are provided with low coolant level sensors, or even low coolant pressure sensors, that will detect an abnormal coolant level and cause a shut down of the generator set. Prototype testing is required to verify the sensing accuracy of the coolant level sensing system under all operating conditions, or nuisance shutdowns can be a serious problem.

6.5.1.5 Not in Auto

A "not in auto" condition occurs whenever a generator set cannot respond to a remote start command. In a paralleling application where draw out circuit breakers are used, the not in auto condition should be indicated when the breaker is drawn out.

6.5.2 AC Protection

All generator sets are required to have protection against damage due to any external overload or short circuit condition. In addition, generator sets in paralleling application must include reverse power (kW) and reverse kVAR protection. Other protection devices can be added at the discretion of the system designer.

Individual load feeders require separate protection, which can be provided by several different devices. Protection practices are similar to those used in utility distribution systems, except that generator sets often will have less short circuit current available. This can complicate coordination, particularly when the switching point is high in the circuit, because coordination must be achieved with two dissimilar sources. Caution is necessary, though, since a generator bus with multiple large generator sets can actually have significantly more fault current available than a utility service, especially on single phase faults.

Basic generator set protection for paralleling applications is also mentioned in **Section 3.4.5 on page 34** of this manual. See **Section 8.4 on page 249** for setting ranges and recommended settings of Cummins generator sets with PowerCommand controls used in paralleling applications.

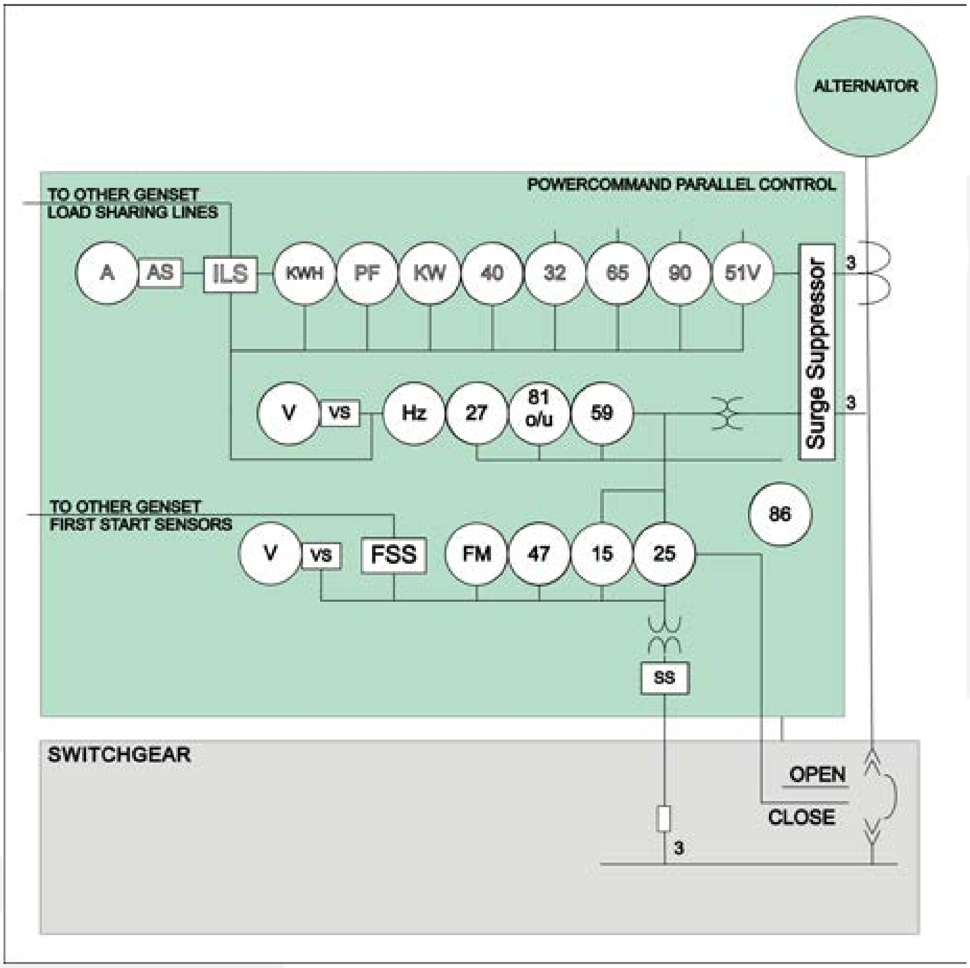

FIGURE 75. ANSI AC PROTECTION FUNCTIONS IN POWERCOMMAND GENERATOR SET CONTROL

6.5.2.1 Overcurrent Protection (Low Voltage Applications)

If the alternator on a generator set is subjected to a short circuit or overload condition, the internal operating temperature of the machine will quickly increase. If the overcurrent condition is not remedied, the alternator will overheat, the insulation will fail, and the generator set will fail and be seriously damaged. A detailed description of alternator overcurrent protection considerations is provided in Cummins Power Generation manual T-030, Generator Set Applications. That document concludes that proper protection of the alternator requires matching of the alternator thermal damage characteristics to the overcurrent protective functions. Also, care should be taken to design in protection of system components for over voltage conditions which may occur due to single-phase short circuits in the system. In general, codes and standards do not require the generator set to be protected from damage due to internal faults or other failure conditions, but medium voltage generator sets often include some protection against extensive damage due to internal failures.

Codes and standards in place in most areas require that alternator protection be provided to prevent damage due to external overloads and short circuits, but these codes and standards generally do not address parallel generator set applications and their specific needs.

The paralleling circuit breaker functions primarily as a switching device to connect a generator set to the paralleling bus. When the paralleling breaker includes an overcurrent trip function it is critical that the functions and settings of that device are coordinated with the generator set and its required protection.

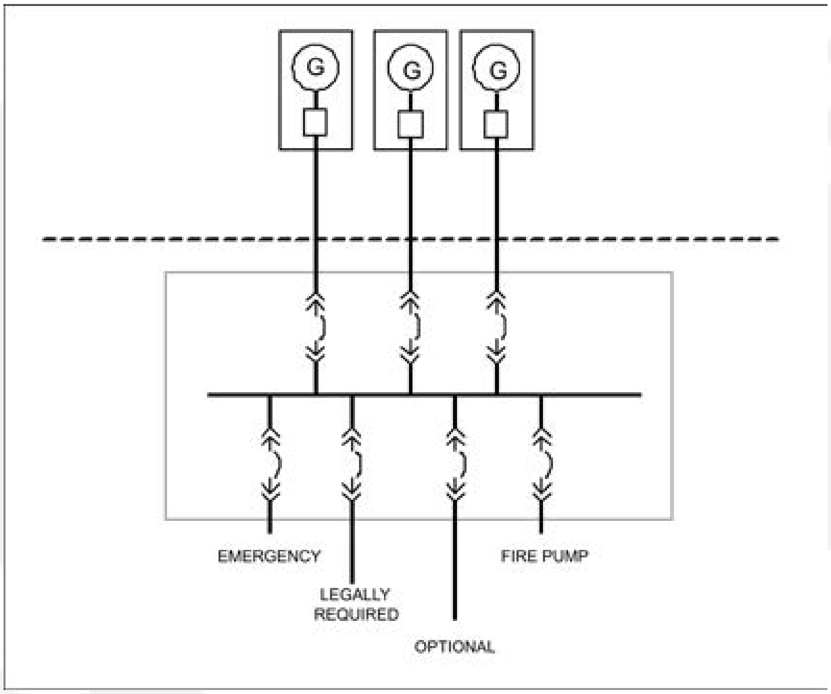

FIGURE 76. PARALLELING SYSTEM WITH DISCONNECTS AS USED IN OUTDOOR IEC PROJECTS.

The figure above shows a typical system with generator sets. If the generator mounted main breaker is provided, it is often a molded case circuit breaker with a thermal-magnetic trip unit. The downstream paralleling breaker is generally a power circuit breaker. This can result in two problems. First, if there is a fault between the two breakers in the system, the generator main breaker may, but the paralleling breaker may or may not trip. The figure below shows typical trip characteristics for these breakers and highlights the problem.

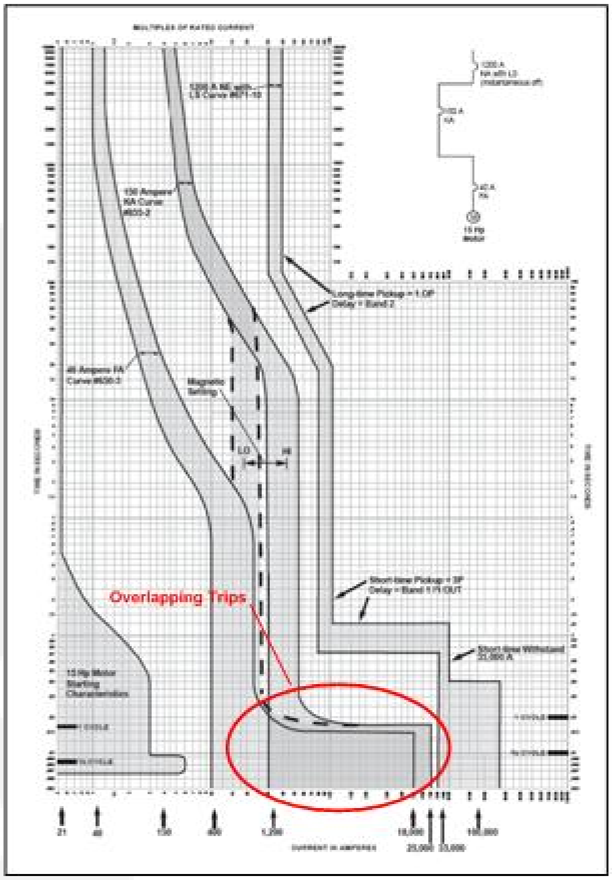

FIGURE 77. WHEN BREAKERS WITH INSTANTANEOUS TRIPS ARE IN SERIES, COORDINATION IS NOT POSSIBLE.

If a fault occurred downstream from the paralleling breaker, the generator main breaker could trip before the paralleling breaker. This is likely simply due to the characteristic differences between the molded case and power breaker trip units. (Molded case breakers always have integrated instantaneous trips. The paralleling breaker may or may not, and may not trip as fast as the molded case breaker. Also, it should be recognized that molded case breakers are often not rated to carry full rated output continuously, while power circuit breakers always are.)

If the generator main trips before the paralleling breaker, the generator set may be protected, but another adverse condition can occur: The paralleling control system monitors the position of the paralleling breakers to determine when the generator set is closed to the bus. Based on this information, the system controls fuel systems and excitation on all the other generator sets in the system. If errant condition information is inserted into this control system, the entire power system can fail.

One way to address this issue is to be sure that if the generator main breaker is used, the paralleling breaker will be forced to open at any time when the main breaker is open (for any reason). This can be accomplished by inserting a set of auxiliary contacts from the main breaker to trip the paralleling breaker.

Another alternative is to not use a generator main breaker (where codes allow this), and provide alternator protection using other means (over current or differential protection, for example). This can be as simple as moving the paralleling breaker into close proximity to the generator set. (The feeder between the generator and paralleling breaker is still unprotected, but this may be more desirable than dealing with the problems of generator main breakers to some designers.) It is also possible that the generator set could be protected using a protective relay rather than a circuit breaker, since the paralleling breaker will generally provide the disconnect means required in most applications. Whatever the case, the important thing is to be sure that the protective relaying is selected based on the alternator thermal damage curve. Also, the relaying should not be generator set mounted unless it is vibration tested to verify acceptable life when mounted on the generator set. (Most protective relays are designed for use in stationary switchboards, and are not verified as suitable for generator set applications.)

6.5.2.2 Paralleling Breaker Trip Settings

The paralleling breaker for each generator set should be set to protect the conductors from the generator set to the paralleling breaker, assuming alternator overcurrent protection is provided with the generator set. With the generator set protected, the paralleling breaker can be set to protect the conductors, because a fault in the generator could result in an overcurrent condition that would damage the conductors, since all the paralleled generator sets would feed a fault in a generator backward through the paralleling breaker.

6.5.2.3 Rationale of Design and Base Settings for Generator Set AC Protection

AC protective functions that are provided for the generator set should also provide necessary protective functions for the conductors to the paralleling breaker; and may provide some nominal level of load protection as long as this protection does not impact on generator set reliability. Keep in mind that the protection that is provided integral to a generator set control or voltage regulator is intended to protect the generator set, and should be set for that purpose. Other incremental protection will be required for other parts of the system. The rationale used in defining the requirements in this section is common for all generator sets, but the exact settings change somewhat from model to model. The examples of settings used in this section are typical for all generator sets up to approximately 3000 kVA.

All protective equipment that is generator set mounted must be prototype tested, ideally with the specific machine used, to verify the ability of the equipment to withstand the vibration and temperature extremes present on the machine. Relaying equipment that is not prototype tested to deal with the generator set environment should not be applied on a generator set or even in a generator room. Generator sets in critical applications should utilize protective relaying that is capable of meeting stringent IEEE voltage surge and RFI/EMI requirements (such as are found in UL category NRGU equipment), since voltage surges and electromagnetic interference are common in generator set applications.

6.5.2.4 Over Current Warning (51A)

The warning function is provided to give an operator the opportunity to relieve the load on the alternator before it reaches a condition where it needs to shut down in order to protect itself. The control system should be set up to provide an external signal to command automatic load shedding on occurrence of this event. In most facilities it is rare for generators to operate at a power factor of less than 0.8, and the 10% and 60 second settings provides a level of protection against nuisance indication of a fault condition, even on a heavily loaded machine. Alternator selections should always have at least a 10% overload current capability to make it safe to use this function as a warning condition. (With Class H insulation, the overload capability is often achieved by use of alternators with maximum temperature rise of 125 °C. More information on alternator ratings, sizing, etc. is in T-030, the Cummins Generator Set Application Manual.)

Setting: Output current on any phase at more than 110% of generator set rating for more than 60 seconds. Warns an operator that unless addressed the generator may be shut down.

6.5.2.5 Over Current Shutdown (51)

Overcurrent protection is the most critical protection function in an alternator protection scheme, because most modern alternators (those with excitation support systems such as permanent magnet generator driven voltage regulators) have the inherent ability to drive the alternator to destruction on a short circuit or ground fault condition. Thus, the overcurrent protection function must be matched to the thermal damage curve of the alternator. The protection need not allow adjustment of the protection curve setting (in spite of the variation of alternator capability due to over-sizing for motor starting, etc.) because the function also provides code-required overload protection for a fully rated conductor set from the alternator to the first level of distribution. Use of less restrictive settings may result in the cables not being protected, or the necessity of over sizing the conductors. Also, the over sizing of an alternator does not significantly change the time required to trip at a particular current level, so it is of very limited value to allow changing of this setting.

For acceptable system reliability, it is critical that this function be coordinated with other overcurrent devices in the balance of the distribution system connected to the generator set.

Setting: Output current on any phase is more than 110%, less than 175% of rating, and approaching thermal damage point of alternator as described on a time overcurrent characteristic curve.

6.5.2.6 Short Circuit Shutdown (51)

The settings and rationale for this protective function are the same as for over current, but the discrimination in alarm annunciation allows the user to understand the problem as a short circuit rather than something that might appear as a normally occurring overload condition, in a similar way to having the alternator provided with both a 51 and 51 volt protective function. However, it is not rational to accelerate the tripping of an emergency generator faster on a short circuit than on an overload because the damage point is the same on either condition, and emergency machines are intended to remain on line until the point that they are about to be damaged under both types of conditions to improve the probability of selective coordination (discrimination).

Setting: Output current on any phase is more than 110%, more than 175% of rating, and approaching thermal damage point of alternator.

6.5.2.7 Under/Over Voltage Protection (27/59)

Operation of any electrical component at excessive voltage levels (more than 110% of rated voltage) can result in deterioration of insulation eventually leading to failure. Degradation in insulation is proportional to the degree of over voltage and its duration. Over voltage situations may occur as a result of an external transient, such as a lightning-induced surge; operation of the system, such as the interruption of an inductive load; or may be the result of a failure of the control or excitation system of a generator. These considerations are much more significant on medium voltage generators than low voltage machines.

Under voltage conditions can be just as damaging for both generator and load components. If the generator is operated at a voltage substantially below the rated value, the alternator’s effective reactance is increased and the machine becomes less efficient. Load components such as motors tend to draw more current as the voltage decreases and this can result in overheating. Balancing this, however, is the fact that many low voltage alternators are designed for operation at a range of voltages, and operating at a lower voltage may be acceptable with use of appropriate ratings.

Under voltage settings should be coordinated with the overload alarm and shutdown settings on the generator set and the settings for the voltage roll-off functions in the voltage regulation system. Voltage roll-off (also termed “torque matching”) is a common control function integral to most voltage regulators that will cause the voltage to intentionally drop as frequency drops, in order to unload the engine and allow the engine to recover quickly from sudden kW load application or overload conditions. Effectively, the voltage regulator intentionally drives the voltage low temporarily to allow the engine to recover from overloads. The under voltage protection should not operate over the time period or magnitude of under voltage that occurs during a normally occurring voltage roll off event, or during a short circuit or overload event, because the generator set is required to drive fault current into the load to hopefully clear the fault before it is necessary to shut the generator set down on a short circuit or overload current event.

In spite of the fact that this protection is critical for loads in many situations, it must be recognized that it is unlikely that a generator set will be damaged by over or under voltage. In particular in a paralleling situation it is not possible for an excitation system or other generator set specific failure to cause an over/under voltage condition on generator sets that are paralleled. In that situation, an over or under voltage condition will have been caused by an external impact on the generator sets. Consequently, the over voltage protection may be set at a level that is sufficient to protect the alternator from an over voltage condition, but will not protect the loads. Separate protection for each sensitive load is desirable, or protection for the system bus that is separate from the generator set control. Over and under voltage protection is often required for utility paralleling applications, but is typically provided by components other than the generator set controller.

Note that under and over voltage protection should be disabled on a generator set while it is synchronizing to a system bus, since an oncoming generator set may need to match system bus conditions in order to safely connect, and provide necessary resources to drive the bus to normal conditions.

Dynamic testing of a generator set under various load and unload conditions replicating actual site conditions should be done at commissioning in order to establish if any changes are needed to these settings.

Settings: Undervoltage, 75% for 10 seconds; Overvoltage: 120% for more than 1 second. Voltage levels greater than 130% of nominal should trip instantaneously.

Note in the figure below that the critical portion of the curve (shown here at approximately 0.2 per unit kVAR leading), is nearly vertical, indicating that power factor is not as critical as kVAR level in protecting the generator set from misoperation on this condition.

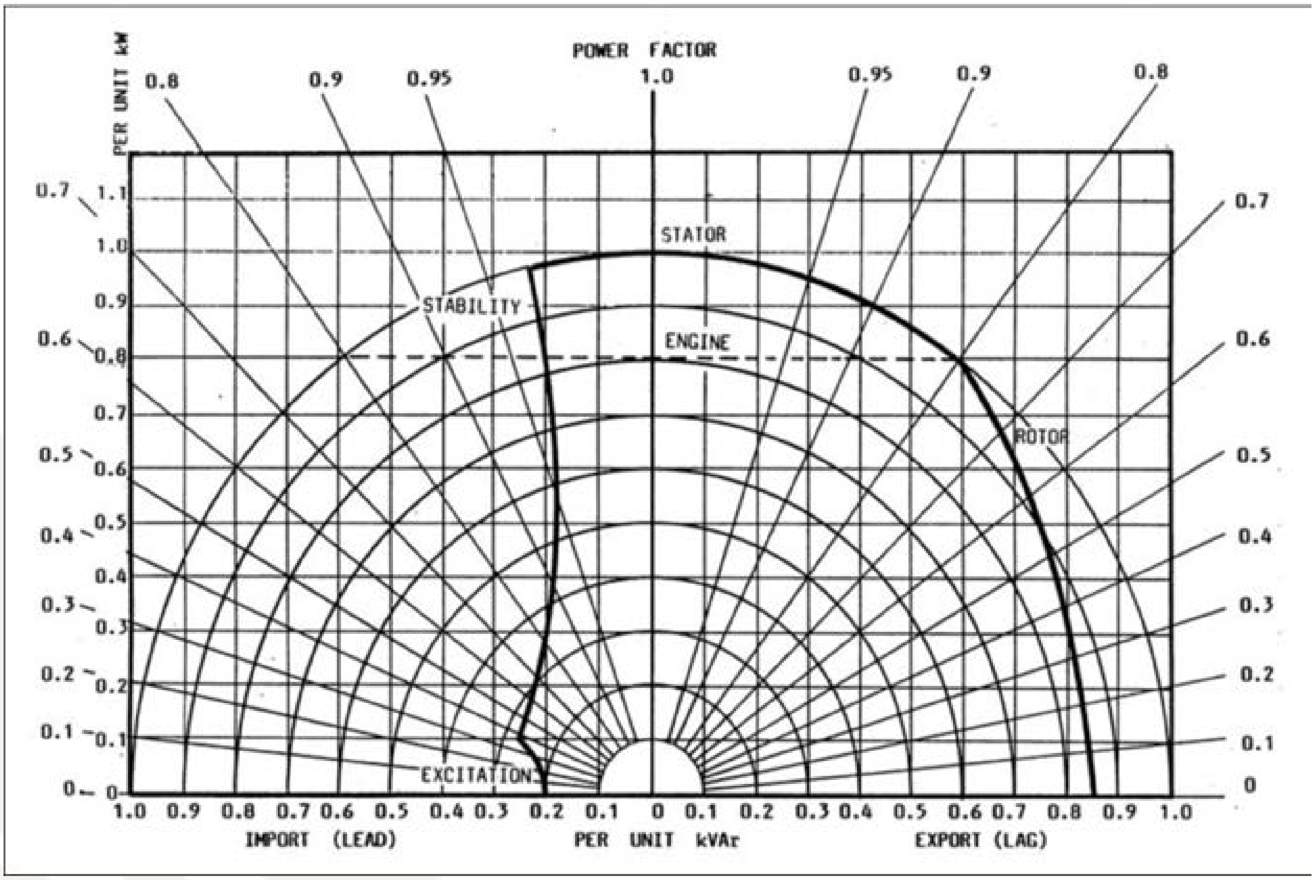

FIGURE 78. A REACTIVE CAPABILITY CURVE FOR A TYPICAL SYNCHRONOUS GENERATOR SET.

6.5.2.8 Reverse VAR (Loss of Field) Protection (40)

An excitation loss module (one for each generator set) or other reverse kVAR function should be provided to monitor the generator voltage regulator and excitation system. In the event of an interruption of exciter field voltage, the module energizes an integral relay. This relay signal initiates the opening of the main generator breaker, sounds the alarm horn, and lights a red Loss of Field indicator lamp on the corresponding paralleling control panel.

The excitation loss module should include a time delay or logic to prevent tripping on transients and a time delay to prevent operation during engine starting.

Another option to providing protection against this failure mode is to utilize a reverse VAR relay. A reverse VAR relay functions in a similar fashion to a reverse power relay, in that it monitors magnitude and direction of VAR flow. If the relay detects a reverse VAR condition, it can operate to isolate and shut down the generator set before it is damaged.

This protection for a generator set is critical in any situation where the generator set is paralleled, including applications where a generator set is applied with a closed transition transfer switch. When a generator is paralleled with another source and looses the ability to provide reactive power (kVar) to the system, the magnetic field that maintains synchronous condition of the generator with the bus is lost, and the alternator can be severely damaged due to pole-slipping. This can occur in a very short period of time.

Setting requirements for reverse VAR relays vary greatly between alternator manufacturers, and even within a single manufacturer's product line. So, settings of this device should be decided based on the protection needed for the specific alternator used.

The reactive capability curve of a generator describes the ability of a specific generator to produce or absorb reactive energy. This curve must be used for developing proper settings for a specific site.

With reactive capability curve for a typical generator, shown in **Figure 78**, the generator performance for various magnitudes of reverse VAR can be assessed. Note that curves for various generators differ and an operating chart obtained for the specific alternator must be used for accurate results. Negative reverse kVAR capability can vary from as little as 0.10 per unit reactive to more than 0.60 per unit reactive.

Note also that not all reactive load sharing control systems are operational over the possible range of reverse kVAR conditions. Consequently, the sequence of operation of the loads must be carefully designed so that while the generators are closing to the bus and loads are added; neither the reverse kVAR protection limits of the generators nor the limits of the load sharing control system are violated.

Reverse reactive load sharing also impacts on the accuracy of reactive load sharing between machines, because the correction signals from the load sharing controls become relatively large compared to the total correction driven by the AVR to the exciter field.

Note that some load devices are capacitive in nature, and cause misoperation of reverse VAR and loss of field relays. These devices include power factor correction equipment for rectifier-based loads, such as UPS equipment. If this equipment is connected to a generator set and the generator set is lightly loaded, the protective relaying may operate to protect the generator. There are no easy solutions to this problem, except to be sure that lightly loaded generator sets are not subjected to leading power factor loads.

Care must be taken during operation of power factor correction equipment to ensure that the power factor relative to the system bus is always maintained at an acceptable level regardless of load transients. Unit power factor correction applied to individual loads is preferred. Power factor correction should be enabled only when necessary to prevent other adverse conditions. Even then, the unit power factor correction of loads such as the discharge lighting may result in leading power factors being produced if the lamp enters a re-strike mode following voltage fluctuation as the capacity may remain in circuit with the lamp load removed. Where many lamps are involved, this may result in excessive leading power factor and the risk of loss of voltage control.

6.5.2.9 Under Frequency Shutdown (81u)

Under frequency does not damage a generator, but is generally indicative of an overload (kW) condition on the generator set. It may also occur when the engine is unable to carry load normally due to incorrect settings, component failure, or fuel condition. This protective function, like under voltage, should be coordinated with the overload alarm and shutdown settings on the generator set and the settings for the voltage roll-off functions in the voltage regulation system. Under frequency is the most positive indication of overload on a generator and is valuable because it can detect an overload that is caused due to poor fuel condition or other events that occur whether or not a generator set is operating normally.

Under frequency is also a normally occurring event on a generator set, especially when large load steps are added to the generator set or when a generator set is synchronizing to an overloaded bus. The default settings are selected at a point that positively indicates a very adverse overload condition, and are unlikely to cause a nuisance tripping condition, especially while synchronizing. Some suppliers logically disable this function while synchronizing to avoid any possibility of tripping when synchronizing. Setting the under frequency set points “tighter” requires a clear understanding of normal load changes in the system and of the generator set’s response to these load changes.

Typical Setting: 6 Hz, 10 seconds.

6.5.2.10 Over Frequency Shutdown/Warning (81o)

Over frequency is analogous to over speed in a synchronous generator set. The engine protection is commonly used to drive the protection of the engine, as it is more positively detected than frequency in generator sets that have electronic governing arrangements. (Frequency sensing can be disrupted by voltage waveform distortion and requires a longer period of time to sense than over speed, which is detected by the control by a magnetic pick-up monitoring the flywheel teeth on the engine.) Consequently, this function is disabled as a default on most generator sets, and it is rarely used.

6.5.2.11 Over Load (kW) Warning

This function provides a warning indication when the engine is operating at a kW load level over a set point, and/or due to under frequency.

This function is primarily used to signal load shedding in the system, so that the generator set can continue to operate and provide power to the most critical loads in the system. The U.S. National Electrical Code requires this function be provided to protect the reliability of service to emergency and legally required loads in systems where the generator set also serves optional standby loads.

The setting range allows the user to anticipate an overload condition and provide better protection for critical loads, as well as to respond to the specific dynamics of the facility where the equipment is installed. Default settings are designed to prevent nuisance indication of a problem, and are built around the concept that most Critical Applications generator sets can carry low level overload conditions for a short period of time.

This is a function that should be set at the commissioning of the generator set, based on the ability of the generator set to carry load under site conditions and the expected nature of the dynamics of the load at the site.

Note that load shedding to protect the reliability of service to the most critical loads in a system is a code requirement in some regions.

Typical Setting: 105%, 60 seconds.

6.5.2.12 Reverse Power Shutdown (32)

When the engine of a paralleled synchronous generator fails, the generator, because it can be excited from the paralleled source, will act as a load on the rest of system. This causes the failed engine to continue to rotate as it is driven by the alternator using power from the system bus. Left unchecked, this will cause serious engine damage to the driven machine and can result in bus overload or failure. To prevent such an occurrence, all paralleling systems should be provided with reverse power protection for each generator set in the system.

The reverse power relay monitors power flow through the paralleling breaker and, upon sensing reverse power of a predetermined magnitude for a preset time period, trips the paralleling breaker and shuts down the generator set.

High speed reciprocating engine generator sets normally will be capable of absorbing up to only about 5% of their rated horsepower in reverse power without damage. If a protection relay is set at too high a value, the load of the engine rotating on the alternator will not be sufficient to reach the reverse power limit and the protection will never operate. Consequently, it is necessary to consult the engine manufacturer to determine the proper set points for reverse power conditions. The reverse power limit is not necessarily the same as the regenerative limit for an engine. The value can be determined by prototype test, or by tests at the site. Note that as the engine wears over time the reverse power limit that is acceptable will go down.

Reciprocating Engines can absorb power for a relatively long time (many minutes) without damage. However, if the engine does lose the ability to produce power output and the master control system load control is dependent on “counting” generator sets on line for load control, the system may see a serious, sustained under frequency condition until the reverse power protection operates.

Another consideration in reverse power protection selection is that there is normally some power transfer between paralleled generator sets during transient conditions, and setting the protective devices with stringent parameters will cause nuisance trips and unnecessary load shedding. The setting also must be long enough to allow load share balancing between generators on a parallel bus to occur when a generator set initially closes to a bus or leaves the bus. This time is commonly less that 5 seconds but should be verified under actual conditions at a site. Because damage usually takes a long time to occur, using longer time delay rather than higher trip points is best practice if problems are seen that cannot be adjusted out with the load sharing control system.

Reverse power protection for a generator set is critical in any situation where the generator set is paralleled, including applications where a generator set is applied with a closed transition transfer switch. (Failure modes in some switches can leave a generator set paralleled to the utility indefinitely, and are not detected by protection in the CTTS.) When multiple generator sets are paralleled to a utility service separate protection for the utility is required, and often uses reverse power equipment, but settings and rationale for that are completely different. This topic is covered in **Section 6.10 on page 196** of this manual.

Typical Setting: 5%, 5 seconds typical for reciprocating engine generator sets.

6.5.2.13 Differential Relaying (87)

Differential (87) relaying is recommended for use by the IEEE Red Book (ANSI/IEEE Standard 141-1986 Chapter 6, Section 5.3.6.). When properly installed and adjusted, it will provide a high degree of sensitivity to faults in the portion of a distribution circuit monitored by the device. The implementation in generator set applications is straightforward: Three current transformers (CTs) are placed in the individual phases at the “wye” side of the alternator winding, with 3 additional CTs placed at the load side of the paralleling breaker. This provides a zone of protection covering the alternator, feeder wiring, and paralleling breaker. The two sets of CTs are monitored for current flow, and when the current flow at the alternator does not match the current flow at the breaker, it is assumed that a fault in the circuit is causing the imbalance between the two sets of CTs, and shutdown of the generator set can be initiated. This design is particularly valued because it monitors not only the conductors in the circuit, but also the winding of the alternator itself.

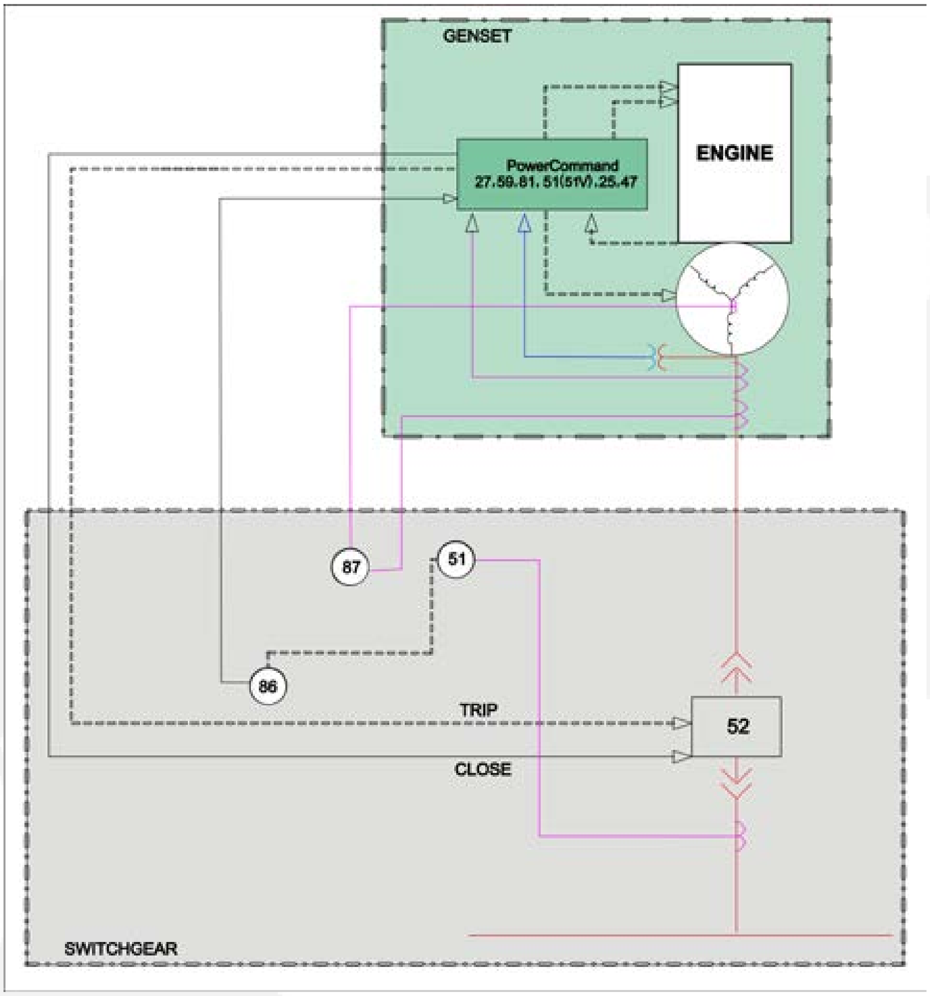

FIGURE 79. RECOMMENDED DIFFERENTIAL PROTECTION STRATEGY ON GENERATOR SETS WITH INTEGRAL LISTED OVERCURRENT PROTECTION, WHEN DIFFERENTIAL PROTECTION IS NEEDED.

Differential relaying is rarely selected for low voltage machines, but is quite common on medium and high voltage generator sets.

When selecting differential relay protection, remember that the CTs used for differential protection should be matched. Use of dissimilar CTs can result in misoperation of some differential protection equipment. A complicating factor in this is that CTs used in switchgear are often not suitable for alternator mounting due to their inability to survive the vibration and other adverse environmental conditions present in a generator set. Also, since internal wiring in an alternator is commonly wire conductors and conductors in a switchboard are commonly bus bars, the physical size of the switchgear CTs make mounting in a generator set problematic.

Generator sets in medium voltage applications are often designed to include differential protection, but is this protection always necessary or even desirable?

The value of differential protection (especially versus common overcurrent protection) is that is very fast in detecting faults in a circuit. High current levels that pass through both sets of CTs will not cause a trip on common events like motor starting, or even on downstream faults that are intended to be cleared by other means. The high speed of operation for faults sensed within the operating zone makes it possible limit damage inside an alternator stator when a fault inside the machine occurs. This can make it possible to allow repair rather than replacement of a damaged stator. The device would also operate on a feeder fault, but in general, once a fault is sensed in a feeder, the feeder will be replaced, so its value in the protection of that circuit is mostly in limiting the duration of a fault, and disturbances in the system that detract from power quality.

Single phase faults are potentially damaging to generator sets. When a single phase fault is applied externally, but close to a generator set, it appears to the generator set as a single phase overload that causes the average sensed voltage to drop dramatically, which causes the voltage regulation to operate at a very high level. The machine is overexcited, causing high current flow in the faulted phase, normally to a greater magnitude than during a 3-phase fault—often more than 10 times rated current. Permanent damage to the alternator will occur within approximately 1 second. In addition, the over excitation normally will cause a significant over voltage condition on the un-faulted phase or phases. This can damage loads, and on some machines compromise the integrity of the insulation in the machine.

The fast operation of a properly designed and adjusted differential scheme lies in its ability to sense and clear a fault quickly. Since the zone of protection commonly includes the alternator, the protection will detect a fault internal to the machine. On larger machines, this is a valuable capability, but on smaller generator sets it is of limited value because the alternator stator will commonly be replaced rather than repaired when an internal failure occurs.

There are potential reliability issues with differential relaying that are associated with tripping at the wrong time under conditions that are clearly not faults. Differential relaying requires precise measurement of current flow at different points in the circuit. This becomes problematic when the zone of protection becomes physically too large, when the CTs are not installed with conductors located in the center of the CT ring, when the CTs are not of appropriate accuracy, and especially when the CTs at the different ends of the protection zones are not identical. While it might seem easy to use identical CTs at each end of the circuit, this goal is complicated by the fact that the CTs at the generator set end of the system are commonly provided by the generator set supplier, while the CTs at the other end are often provided by the switchgear supplier. Further complicating the issue is that the CTs at the switchgear end of the system are commonly designed for rectangular bus bar mounting. Inside the generator set, which commonly has very limited physical space, the CTs are commonly selected with small circular holes to pass the alternator conductors through, and must be vibration-tolerant. So, the CTs that are optimum for the switchgear (and probably for sensing) are physically not well suited to generator set mounted. So, while some would argue that proper selection of system components and proper relaying adjustments will eliminate reliability problems, there are some serious challenges to system reliability in the basic components that are commonly provided.

Another key point to remember is that differential relays do not prevent damage to an alternator, they limit damage. If a relay is properly operating it will not trip until there is actually a line to ground fault somewhere in its zone of protection. In utility and other prime power distribution systems this is a valuable capability, because larger, higher voltage equipment is commonly repaired whenever possible. By limiting the duration of a fault, it is possible to limit damage to the stator laminations, so a machine can be effectively repaired. However, in smaller alternators, particularly in those under 3000 kVA, it may be more practical to replace the alternator than repair it. The lamination slots and coil assemblies are relatively small and difficult to strip of insulation. The small size also makes it difficult for field processes, which can not duplicate the factory insulation equipment and processes, to make the insulation as robust and reliable as a new stator could provide.

Another point to consider is that many digital generator set control systems incorporate overcurrent functionality as a part of their design. These systems can utilize CTs and sensing/logic that is equal or superior to the protection that can be provided by circuit breakers or even protective relays. If the CTs for this system are located at the neutral side of the alternator, they will sense a fault, even within the alternator, although these overcurrent functions will not be as fast as differential protection at detecting and limiting damage.

Their presence, though, means that the conductors from the generator set are protected from overcurrent starting at the terminals of the alternator. So, if differential protection for the alternator is desired, the differential relays can be served by CTs that encompass the alternator only. The generator set supplier can supply, mount, and wire the CTs, and use identical equipment so that many of the weaknesses that hurt reliability with differential protection can be avoided.

On 15kV class machines the alternator stator is expensive enough that it is more likely to be repaired rather than replaced, so it will make more sense to try to limit damage in the machine and have it repaired, in that case.

6.5.2.14 Phase Sequence Voltage (47)

The phase sequence voltage function is used in the generator set paralleling application to verify that all bus phase voltages are available (proper magnitude) and phase sequence prior to synchronizing or connection of the generator set to the bus. Connection of a generator set to a bus with opposite phase sequence will cause immediate and serious damage to the machine. Phase sequence sensing requires 3-phase bus voltage sensing, so that the bus voltage sequence can be compared to the oncoming generator voltage sequence.

6.5.2.15 Bus Voltage and/or Frequency Out of Range

When a paralleling system is starting under black start conditions, the generator paralleling control must determine whether or not the system bus is energized prior to automatically closing its paralleling breaker. In order to be sure that voltage sensing errors do not falsely inhibit closing and do not drive a generator set to synchronize to an extremely low voltage or frequency, “out of range” protection is often utilized.

The protective function is designed to prevent an oncoming generator set from closing to a bus with voltage that is effectively unavailable, or operating under a severe fault condition. The control strategy is based on the premise that if bus voltage is abnormally low that condition will not endure indefinitely, and once cleared, the system can make an attempt to close remaining generator sets to the bus and re-energize the system. The 10% low setting deals with the situation where a “ghost” voltage appears on the control system due to conditions in the system design.

The function also aids in diagnosing a failure to synchronize condition by pointing the technician to a bus or bus sensing problem versus an oncoming generator set problem, which is more common.

6.5.2.16 Out-of-Phase Paralleling Protection

An armature rotating within a magnetic field induces a sinusoidal waveform. So, the output voltage of a generator set at constant load at any instant in time is directly related to the position of the rotor with respect to the stator. When generator sets are paralleled out of phase, the voltage waveforms are forced into synchronization and the rotors are forced to new positions almost instantaneously.

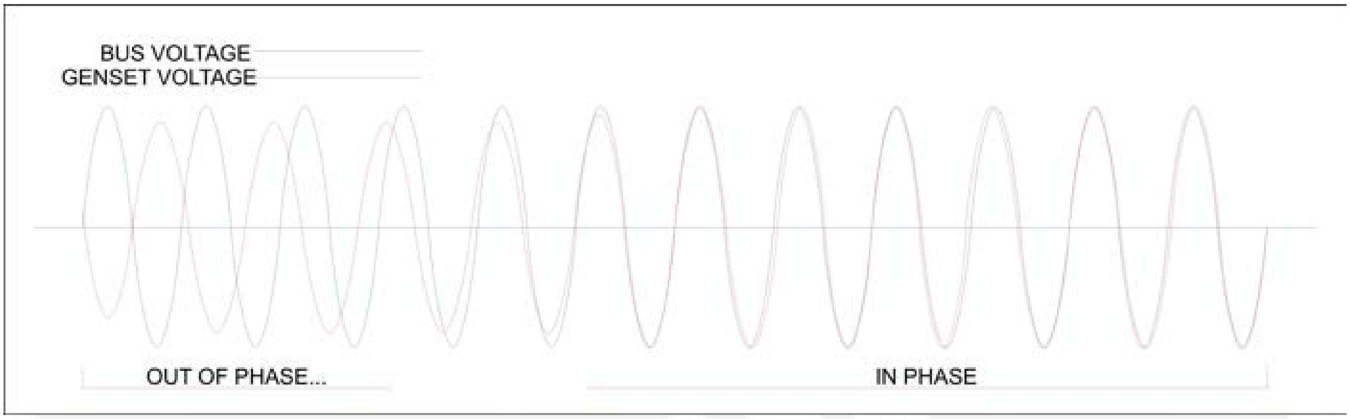

FIGURE 80. VOLTAGE WAVEFORMS FROM TWO GENERATOR SETS, SHOWING THE DIFFERENCE BETWEEN IN-PHASE AND OUT-OF-PHASE CONDITIONS.

If the two generator outputs are paralleled out-of-phase, the resulting high currents and mechanical forces exerted on the generator sets could have catastrophic results. Damage to the generator sets could involve internal engine component failure, drive disk separation, rotor lamination slippage, excitation system failure, or power and control cable damage.

The magnitude of damage is a function of the phase differential and the relative size of the generator sets being paralleled. Out-of-phase paralleling of a commercial generator set with a utility source will almost always cause damage.

Several levels of protection are used to prevent damage caused by out-of-phase paralleling.

Some basic things to be considered are –

- The generator set should include a rugged mechanical design incorporating rigid bracing for the windings and paralleling suppressors across the exciter rectifiers to limit damage that would be caused by an out-of-phase paralleling operation.
- Prototype testing should verify that the unit can mechanically and electrically withstand an across-the-line short circuit. (A bolted fault is similar to an out-of-phase paralleling operation in terms of the mechanical and electrical stresses that would be placed on the generator set.)
- A system to positively prevent attempting to parallel two or more generator sets to a dead bus simultaneously should be included. Some older systems utilized dead bus functionality on sync-check relaying, but high speed diesels can start at nearly identical times, making this device relatively ineffective during black start situations.
- Paralleling controls should include electrical interlocks to positively prevent out-of-phase paralleling. A sync check (permissive) relay prevents out-of-phase closure of a generator to a live bus in both the automatic and manual modes.

6.5.2.17 Permissive (Manual) Paralleling

To prevent out-of-phase paralleling, a sync check (or permissive paralleling) relay is used. A sync check relay prevents out-of-phase closure of a generator to a live bus in both the automatic and manual modes. This relay monitors the sources and closes an output contact only when an in-phase condition exists.

This contact is wired in series with the breaker closing circuit and blocks the breaker closing signal whenever an out-of-phase condition exists.

Many sync check relays include a dead bus circuit to allow an option to bypass the relay when there is no bus voltage.

The ANSI standard designation for a Sync Check Relay is Device 25.

Sync Lamps or a “synchronized” indication lamp can be provided as a visual indicator of phase conditions for manual (semi-automatic) paralleling operations. Traditionally a pair of lamps was connected across the circuit breaker to be closed. When the lamps are lit, indicating a voltage differential between the incoming set and the bus, the two sources are not in phase and it is not safe to close the breaker. When the lamps are dark, the two sources are in phase and it is safe to close the breaker.

When used, synchronizing lamps should have large clear lenses, with easily visible filaments, so an operator can verify phase relationship, even in bright room lighting conditions. Alternately, digital paralleling controllers are often provided with a display that indicates the degrees out of phase, so an operator can clearly see when synchronized condition is reached.

Although sync lamps provide a visual indication of in-phase/out-of-phase conditions, they do not provide positive protection for the system. Sync lamps do not prevent the operator from attempting to close the breakers when power sources are out of phase. This function is performed by the sync check relay.

Figure 80 on page 189 shows two in-phase waveforms. The waveforms have the same amplitude and frequency. In the out-of-phase example, waveform A leads waveform B by 90 electrical degrees.

The figure below shows the output waveforms of two out-of-phase generators. The lower graph shows the voltage differential across the sync lamps as the two sources drift in and out of phase. At point X, the two sources are in phase and the voltage differential is zero. The lamps are dark and it is safe to parallel. At point Y, the two sources are 180 degrees out of phase, providing the maximum voltage differential between the sources. At this point, the sync lamps are brightly lit. At point Z, the sources are shown in phase again. Notice that as the voltage of 2 sources is synchronized at point X and Z, the voltage difference between the sources goes to zero.

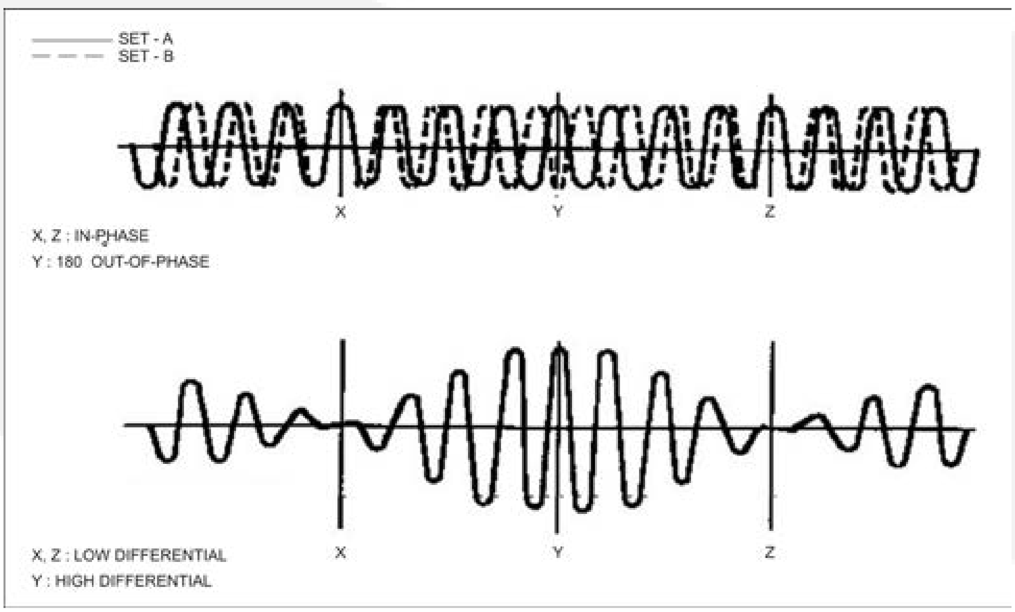

FIGURE 81. VOLTAGE WAVEFORMS DEPICTING 2 SOURCES SYNCHRONIZING USING SLIP FREQUENCY SYNCHRONIZING.

6.6 Ground/Earth Faults

A ground/earth fault occurs when one of the active conductors of a power system is (usually accidentally) connected to earth ground, causing current to flow through the earth or ground path back to the source, rather than through normal current paths (that is on the phase and neutral conductors).

In the figure below, phase conductors are represented by a red line, neutral by black, and ground (earth) by a green line. The system design is typical of a separately derived power system. A ground fault is shown occurring on the load side of the feeder breaker, and two paths for fault current back to the source of the power (the generator sets).

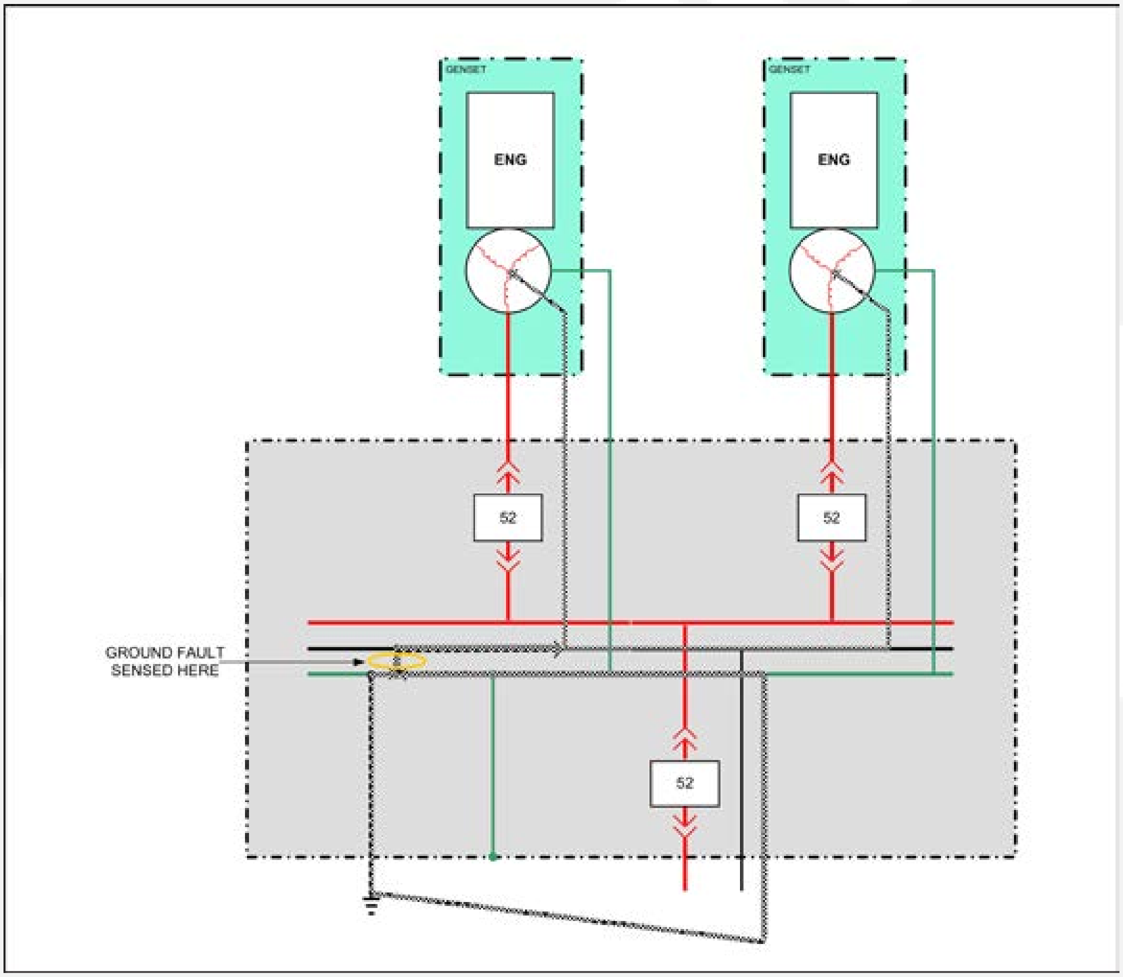

FIGURE 82. TYPICAL SEPARATELY DERIVED PARALLELING SYSTEM SHOWING GROUND FAULT SENSING AND GROUND FAULT PATH.

A ground fault condition differs from other short circuit conditions in that it is typically a high impedance fault, meaning that even though current in the circuit is higher than normal, it may not be high enough to trip protective devices. Since ground fault conditions can be very destructive and can escalate quickly into more damaging conditions, it is critical to sense them and clear them quickly. To do that, sensing must detect them quickly, and the strategy is to sense current flow in locations where the level should be very low, so it is easier to detect. As shown above, the best place to do that is in the neutral to ground bonding connection in the switchgear.

Ground faults can cause serious damage at the physical location where they occur, even though actual current magnitudes can be considerably lower than the trip settings of protective devices in the system. Current magnitudes are lower due to impedance in the current flow path, including the fault itself, the ground path, and through an arc, if that occurs. When a ground/earth fault occurs within a switchboard/switchgear line-up, it can cause an explosion which would destroy the equipment within 100 milliseconds or less.

A ground fault can also occur through a human body, which obviously is a condition to be avoided as serious injury or death can quickly occur. Specialized sensors are required to quickly detect these conditions and disconnect power to prevent serious injury or death.

Ground faults of various types are commonly caused by contamination due to dust/dirt/moisture/or other conductive materials, insulation damage, mechanical stress that causes damage, or over voltage conditions that compromise insulation integrity. So, they can generally be prevented by proper maintenance of equipment, servicing only de-energized equipment, and by proper practices in the use of electrical devices.

Ground fault equipment that is designed to protect equipment, such as motors, is termed “ground fault protection (GFP)” in North American applications. Devices that are intended protect humans are termed “ground fault circuit interrupter (GFCI)”, or earth leakage circuit breakers (ELCB) in IEC terminology.

Ground fault equipment is designed to protect equipment and GFCI equipment is designed to protect people, neither of them provides protection for sources. This is a critical point: when a generator source is powering life safety loads, ground fault tripping protection that will shut off the generator set should not be used. A ground fault condition will not damage a generator set unless the fault is very close (electrically) to the generator set, and the generator set has inadequate overcurrent and over voltage protection. (A ground fault external to a generator set looks like an overload to the generator set.)

Ground fault devices monitor and calculate the vectoral sum of the phase and neutral leg (see figure below), or as is shown in the figure above, by using a sensor at the bonding point in the system. When the vectoral sum of the measured current is not balanced (beyond the set point of the ground fault sensing), or if there is current sensed at the bonding point the nearest upstream breaker is tripped and/or an alarm is given.

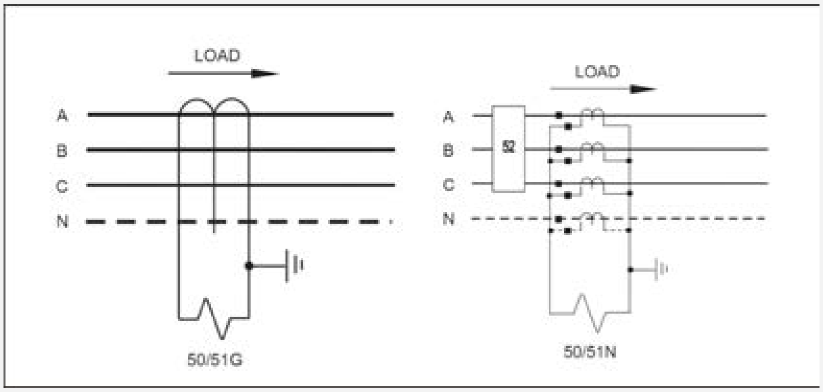

FIGURE 83. TWO COMMON MEANS OF GROUND FAULT SENSING.

Above, two common means of ground fault sensing include zero sequence sensing (left) and residual sensing (right). Zero sequence sensing uses a single large CT around all conductors. Residual sensing uses four matched CTs, with one around each phase and neutral.

Ground fault sensing systems are subject to nuisance tripping due to asymmetrical currents flowing in normal operation of some loads, particularly motors in across the line starting configurations. So, it is not uncommon for them to nuisance trip if they are not properly adjusted. Settings are problematic, because as noted earlier, the current flow during a ground fault condition is usually not very high, and they need to trip quickly to prevent an arcing fault from escalating into a 3-phase fault. A trip without evidence of problem in the field usually results in operator resetting of the device settings, which can easily make the system ineffective in providing its intended protection.

Ground/earth fault protection should never be applied at the terminals of a generator set in a paralleling application. This protection should be located downstream from the paralleling bus for proper sensing, better accuracy, and better reliability.

If multiple level GFP systems are used, 4-pole transfer switches should be specified. If 4-pole transfer switches are used, the generator neutral bus should be grounded to establish a ground point on the generator set side of the system. Utility neutral is grounded at the service entrance.

If GFP systems are not used, 3-pole transfer switches may be specified.

Special attention must be given to coordination of ground fault schemes that involve paralleling breakers in North American applications due to code considerations. A common misconception is that all sources must have ground fault protection if they are 1000 amps or larger, and voltage is greater than 150 VAC line to ground. However, it must be recognized that ground fault protection is not intended to protect sources, its intended to protect the loads or distribution system downstream from a source. Consequently, in a paralleling application the highest level of ground fault protection should be located at the feeder level immediately downstream of the parallel bus. This location eliminates sensing issues due to location of bonding jumpers in the system, as well as preventing a single ground fault from disabling the entire system.

In any event, if the system is intended for emergency use, ground fault trips are not required, regardless of breaker size or location.

Further information on ground fault considerations can be found in application manual T-011, Transfer Switch Application Guide.

6.7 Surge Protection Devices

Surge protection devices divert the high frequency surge voltages caused by lighting, or other switching phenomenon safely to ground and away from sensitive equipments. A typical surge diverter has the following basic requirements:

- Does not pass any current at normal power frequency voltage;
- Breaks down as quickly as possible once the abnormal high frequency voltage occurs; and
- Discharges the surge current without damaging itself and protects the equipment.

The possibility of lightning or switching-induced surges must be ascertained by the system designer and incorporated in the protection scheme. Suppressors are commonly provided at the alternator in medium voltage generator sets.

6.8 Breaker Misoperation

Paralleling control systems require the use of power circuit breakers which are designed to operate quickly and reliably to connect a generator set to a common bus or to the utility. When the breaker does not operate properly when commanded, serious operational problems can result, including total system failure. Further, the auxiliary contacts for the breaker are used to signal changes in the operational modes in the control system, so failure of a breaker auxiliary contact can be as detrimental to system operation as failure of the breaker to operate.

6.8.1 Fail to Close

If a breaker is signaled to close by a paralleling control system, it must close within 5 cycles to avoid potential out of phase paralleling and damage to the generator set, which might occur due to shift of the phase relationship between the generator set output and the system bus due to frequency change of the generator set or a bus frequency change, such when load suddenly changes. If the breaker is signaled to close and does not, the primary problem is usually a loss of capacity for the system bus. However, if the generator set that fails to close to the bus is the first unit to attempt to close, it may prevent any generator set from closing to the bus. (A de facto total system failure.)

Control circuits can be added to a system to monitor the closing circuit of a breaker, so that if the breaker doesn’t close within a specified time period (normally less than a second), the breaker can be tripped and locked out. This may cause a breaker that is really closed to be forced to open, but prevents potential system failure. This could be considered to be acceptable since the condition is not very common, and operation without the alarm can cause total system failure. The control circuit usually monitors one or more auxiliary contacts on a breaker (sometimes one normally open and one normally closed contact from different switches), trips the breaker if the contact set does not change state within a programmed time period, and indicates a failure to close alarm.

6.8.2 Auxiliary Contact Failure

As noted above, an auxiliary contact failure can unnecessarily shut down an operational generator set and paralleling breaker, so some systems contact logic to detect a failed auxiliary contact so that properly operating generator set can continue to service loads. This can be accomplished in a number of ways.

One mechanism commonly used is to utilize two switches, one with a normally open contact and another with a normally closed contact. When called to operate, the breaker causes the contacts to change state. If only one of the contacts indicates change of breaker position, the system announces that an auxiliary contact failure has occurred, and the generator set continues to operate. It is worth noting that if the warning is ignored, the system will be disabled by a subsequent contact failure.

Another strategy that can be used with paralleling breakers is to compare the phase relationship of the bus voltage and generator set voltage. If the two voltages are matched and the phase difference is zero for a short period of time, the breaker can be considered to be closed and an auxiliary contact failure can be announced. If they are not, the breaker is tripped and the generator set is shut down.

6.8.3 Fail to Open

The failure of a breaker to open in a paralleling or power transfer application is often a much more serious problem than a failure to close. For example, if a generator set is properly operating on a paralleling bus, and the paralleling breaker is commanded to open but does not, the generator would remain connected to the bus, but the load sharing control system would be switched off. This could result in overloading of the generator set (best of a bad situation) or reverse powering the generator set, which would eventually result in a catastrophic failure of the generator set. The failure would often have negative system impacts also.

Consequently, fail to open conditions, which are diagnosed in a similar way to fail to close conditions, will require consideration of what the affected equipment should do when the fail to open occurs. In general if a generator set is closed to a live bus and its breaker fails to open, it should be controlled so that it gets the minimum fuel/excitation level necessary to prevent negative power flow until it can be disconnected or the system can be shut down.

If a power transfer breaker fails to open, it will generally require the system to revert to the previous operating condition. So, if a system is transferring from generator back to utility, it will need to revert to operating on the generator until the breaker problem is diagnosed and repaired.

6.9 Load Protection

6.9.1 Overcurrent

Load circuits in a paralleling application are protected using techniques such as are appropriate for utility-powered systems. The designer should be conscious of the available fault current from the generator sets under both single phase and 3-phase fault conditions and select devices that are rated to operate safely under the conditions as installed.

6.9.1.1 Selective Coordination/Discrimination

A properly designed distribution system will include a selective coordination/discrimination study to verify that the fault current limits of the system are not exceeded, and that fault conditions will not cause cascading trips in the system. The study also provides guidance on settings of the protective devices. With generator paralleling applications the designer should be aware of the available fault current under various fault and operating conditions, and verify that under normal operating conditions the system will function properly.

6.9.2 Over/Under Frequency

A generator bus differs from a utility bus in that the frequency can change dramatically over time, particularly as load changes occur or if a generator set suddenly drops off or connects to the bus without proper control. Most loads that are sensitive to frequency variation have inherent frequency protection that will switch the load off if frequency variation is too great. A problem will occur, however, if the frequency variation settings in the load devices are too sensitive, as it may cause cycling of the load that can make the bus frequency oscillate.

Bus under frequency monitoring is often used as an indicator of generator set overload and to drive the system to shed loads. This is a better indicator of overload than simply counting generator sets because it will allow generator sets to carry the maximum load possible prior to shedding load, and it will also function when the generator sets are degraded in capability, such as when they have poor fuel or partially blocked filters.

6.9.3 Over/Under Voltage

Systems that are powered by synchronous generator sets on an isolated bus can be exposed to very high voltage levels when a single phase fault occurs close to the parallel system bus, or could be exposed to a damaging level of over voltage if large load drops occur. Since different loads have different levels of resistance to the effects of varying levels of voltage, it is best practice to provide protection at the load rather than on the bus as a whole, particularly when it is understood that the action on an Overvoltage condition by the system can only be to disconnect the loads.

Under voltage conditions typically cannot damage loads unless they are maintained for a relatively long period of time. Because of this, while Undervoltage alarms can be used to indicate an abnormal condition, they are usually not used to shed loads. Again, loads that are sensitive to sustained Undervoltage are often protected from this condition, so general bus actions are not necessary.

6.10 Utility/Mains Interconnection Protection

Under voltage, over voltage, frequency, and phase sequence protection is typically included in both exporting and non-exporting types of utility/mains paralleling systems. Utility reverse power protection is appropriate only to systems that do not export power to the grid. The local utility may require other protective devices.

Utility parallel operation demands different settings than are normally used for alternator or load protection. In addition, the monitoring points of a utility system may be exposed to transient voltage conditions that are greater than those typically seen on a generator bus. This typically results in more stringent requirements for voltage surge protection in utility protection applications.

The protection of the interconnection point between the customer owned generator bus and the utility distribution system is generally covered by state or local utility requirements. The most common standards referred to for technical requirements are IEEE1547 and G59 in Europe.

More information on utility paralleling and protection is covered in **Chapter 7 on page 203**.

6.11 Other Failure Considerations

6.11.1 Avoiding Single Point of Failure

In any system that strives for reliability attempts are made to avoid designs that depend on operation of a single component or subsystem, because the failure of that component logically could result in a total system failure. Paralleling systems are often used to avoid a situation where a single generator set is the only emergency power source available.

In paralleling applications, even though they are designed to avoid this failure mode, systems often include subtle weaknesses. While it is not possible to review all the possible system designs for flaws, we can review a typical isolated bus random access design, and point out potential problem areas.

In a typical system, automatic transfer switches (ATS) are used to sense the loss of normal power and provide a signal to start the generator set (or sets). Analog systems, and some digital systems, use a serial logic arrangement to transmit this signal from the ATS to the generator set. The signal (usually a contact closure) is transmitted to the master control panel in the paralleling switchboard. In the master control the contact closure from the ATS operates a relay (or input into a PLC), which is the duplicated and sent to each generator paralleling control panel. The paralleling control then transmits that signal to the generator set control so that the generator set can be started. A system of this type, then, depends on the master control relay or PLC to start the entire on site power system. If the relay (or PLC) fails, the entire system fails.

Note in the figure below that the start signals go through the master/PLC, which is less reliable than if they go directly to the generator set controls.

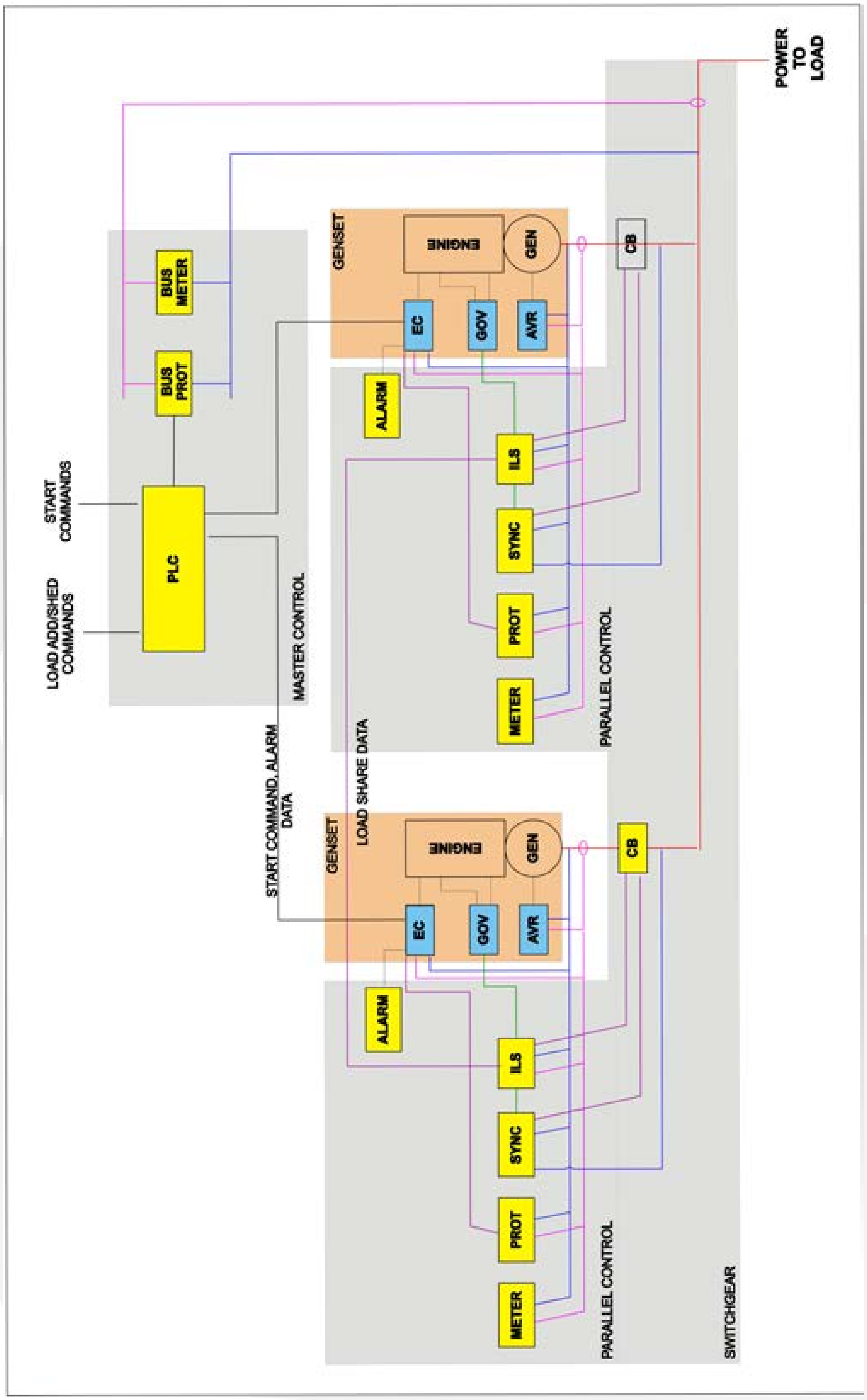

FIGURE 84. BLOCK DRAWING SHOWING TWO ISOLATED BUS PARALLELED GENERATOR SETS CONNECTED TO A MASTER CONTROL.

This problem can be addressed in a number of different ways. Some designs will use redundant relays to transmit the signals through the system. This improves the reliability of the system somewhat, but does not solve the problem because there is no way to know that multiple relays have failed, so one could say that the problem is only postponed until all the redundant relays have failed. Other designs use multiple PLC microprocessors running in parallel to address the issue. This also is only a partial solution, because the processors themselves depend on proper operation of other subsystems, such as power supplies and input/output (I/O) modules. So, if the I/O fails, the system still fails.

A more direct approach is to move to a parallel logic arrangement that has each transfer switch directly starting all the generator sets in the system. Then if one connection fails, most of the system can still function. The reliability of the connection between the generator set and transfer switch can be improved by providing redundant start signals. Often this can be accomplished with one set of wiring being handled by conventional contact closures, and another set of controls through a different media, such as a network interconnection. Provided the network and conventional wiring are run on different paths, they are not likely to fail at the same time.

It is also important to have comprehensible manual fallback schemes in place, so that an operator can take direct control of the system in the event the automatic systems fail. Note that manual fall-back systems are only appropriate for functions that are not time sensitive. For example, it is practical to provide manual load shed and add provisions, but not practical to have a back up governor or voltage regulator; because the operator cannot control these functions fast enough for safe and effective system operation.

In some cases critical functions are single points of failure in a system. When that happens, there are only a handful of alternatives:

- Design out the failure mode
- Provide redundant controls
- Live with the failure mode, and provide the most reliable equipment possible.

Obviously, designing out the failure mode is the most desirable action, and should always be done when that is possible. Redundant controls often add complexity and reduce the reliability of the overall system, so should be used carefully and with full consideration of the fact that not all single points of failure have equal impact on the system, and not all single points of failure have equal reliability. If a failure causes only a nuisance issue, or is unlikely due to the demonstrated reliability of the component or subsystem, redundant equipment is generally not necessary and may make the system not only significantly more expensive, but also less responsive and even less reliable.

When there is not a reasonable alternative for a single point of failure, then the only response of the design is to pick a design that is reliable as possible. Once the design is in place, it should be prototype tested to validate its reliability and demonstrate proper operation through the range of normal operation modes and conditions in the system.

6.11.2 Protection of Conductors from Switchboards/Switchgear

International Electrical Standards require cabling and also bus ducts in an electrical installation to be protected from both short circuit and overload at their point of origin. These requirements help to protect people and the installation from damage due to faults that can occur in the system.

In some regions, it is common practice to install paralleling equipment in a system such as is shown in **Figure 85** below. As the current flow is from the paralleling switchboard to the main switchboard this circuit breaker provides only overload and short circuit protection to the main bus bar system of the main switchboard but not the paralleling switchboard feeder to the source side of the transfer pair. By installing the feeder in this manner the system designer and the installer are relying on the paralleling breakers within the paralleling switchboard to provide the feeder with overload and short circuit protection. While this design/installation has saved the cost and installation of an outgoing feeder breaker within the paralleling switchboard, it has increased the risk of a total standby power system failure, if not a total power distribution system failure. Consider the following points:

- Conductors and bus ducts are manufactured to withstand a rated fault level provided they are protected in accordance with the manufacturers requirements. Should the feeder conductors be terminated onto the main bus bar system of the paralleling switchboard without being protected by a circuit breaker, they effectively become an extension of the bus bar system. This may not be of major concern when the conductors are installed within conduits or bus ducting is utilized, however in countries that utilize ladder or tray cable support systems this is a major concern as the conductors will require bracing along their entire route length so as to effectively maintain fault level of the switchboard (assuming the fault level of the conductors or bus duct is manufactured to sustain the applied fault level).
- Paralleling breakers are designed to stay closed so that fault can be cleared downstream. Theoretically this could be averted by accelerating trip of the paralleling breakers, but that would greatly increase the probability of nuisance tripping. Fortunately for those countries that utilize ground fault protection at the generator set this would introduce requirement to have ground fault trip set to 100 ms or less tripping to prevent destruction of the switchboard.
- Should a termination of the feeder physically fail due to an applied short circuit and ionization occurs it WILL cause catastrophic failure of the main bus bar system within the paralleling switchboard regardless of the reaction time of the Incoming Functional units.
- Increases the chance of a major single point of failure within the power distribution system.
- Regardless of manufacturer, due to trip curve differentials within circuit breakers there is little chance that the incoming breakers will all trip simultaneously when a dead short is applied to the feeder, this will therefore apply uncalculated stress to the feeder medium at its termination point within the paralleling switchboard.

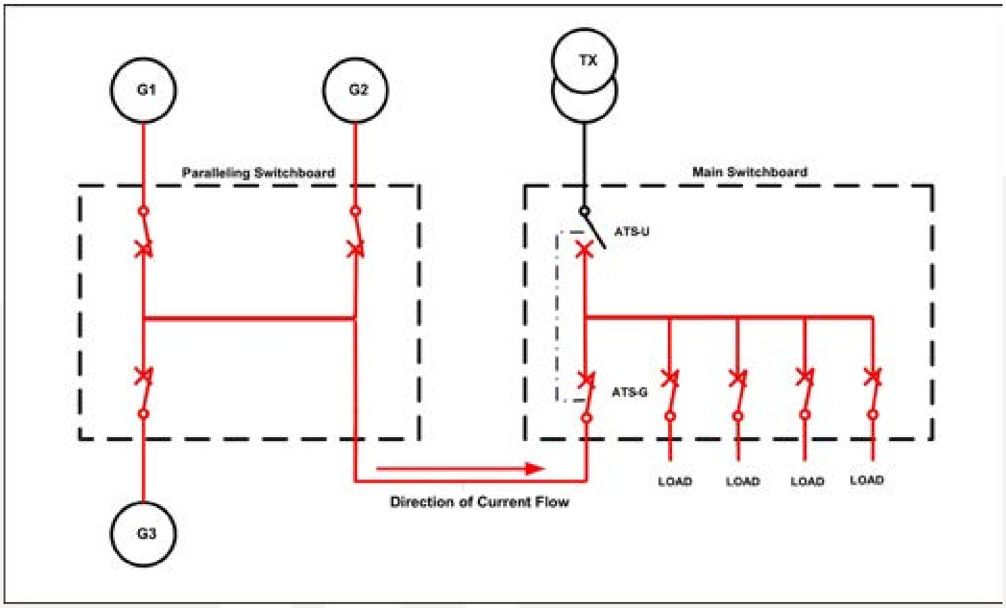

FIGURE 85. A TYPICAL SYSTEM DESIGN THAT SHOWS NO FEEDER PROTECTION PROVIDED ON THE FEEDER BETWEEN THE PARALLELING SWITCHBOARD AND THE MAIN SWITCHBOARD.

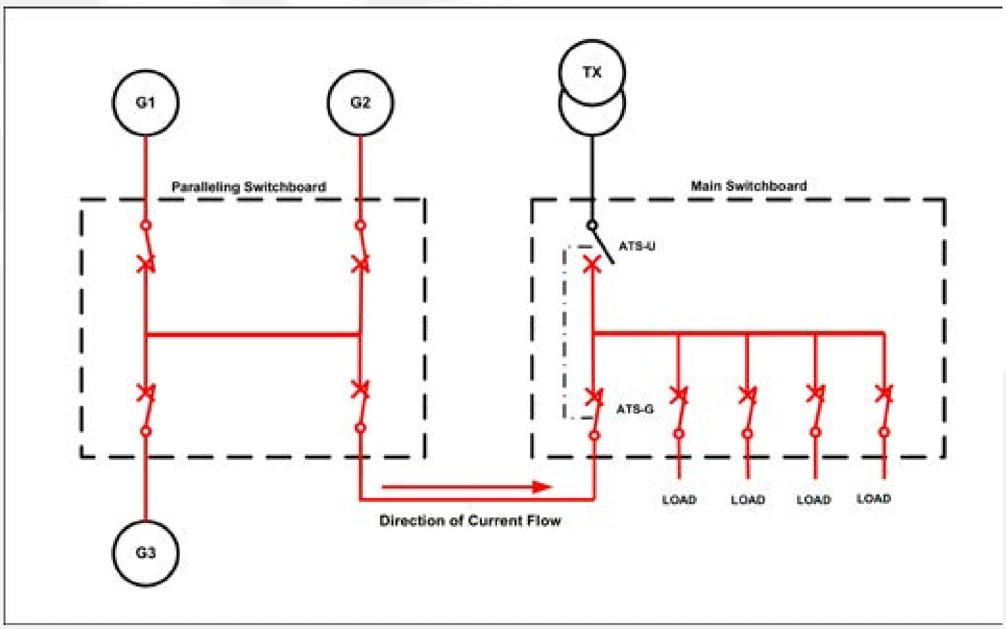

FIGURE 86. A TYPICAL SYSTEM DESIGN THAT SHOWS FEEDER PROTECTION PROVIDED ON THE FEEDER BETWEEN THE PARALLELING SWITCHBOARD AND THE MAIN SWITCHBOARD.

End users purchase and install standby power generation equipment to satisfy country code requirements and to mitigate the risk of a financial loss should the utility power source fail to supply power to their facility. By failing to provide proper protection to the conductors between the two switchboards, the probability of catastrophic failure is greatly increased, with the only benefit being the minimal cost reduction attained by eliminating a single breaker.

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7 Special Design Considerations

7.1 Overview

This section covers special topics that are not a concern in all applications but require attention in situations where they occur. These topics include dealing with grounding, bonding, and ground fault protection; upgrading of existing on-site power systems; paralleling of dissimilar and potentially incompatible machines; and utility paralleling considerations. Each of these conditions requires attention by the system designer in order to comply with local codes and standards, allow for proper operation, and to maintain system reliability and performance.

Grounding and bonding is critical to system design, in that it directly impacts on the physical safety of operating personnel. It also impacts on the life of the equipment itself, in that improperly grounded systems can be subject to very high voltages under some conditions that can be damaging to the equipment; and definitely has an impact on the reliability of fault sensing in the equipment. It is particularly important in paralleling applications, because many designers do not deal with these on a regular basis, and the standard “rules” for grounding and bonding, if blindly applied will often result in an improper design.

Upgrading of systems is, again, something designers often do not deal with, and involves the evaluation of existing equipment, its suitability for a longer life with acceptable reliability, and it’s compatibility with new and demanding requirements that are present in power systems due to latest codes and standards changes and customer demands for “just like the utility” type power. When upgrading includes paralleling existing equipment, the situation becomes particularly demanding because the factors that result in acceptable paralleling are only rarely requirements in most other systems. Furthermore, these requirements go well beyond the normal required topics covered in typical electrical engineering and dance on both sides of the line between electrical and mechanical engineering.

Utility paralleling is also something that is generally not considered in emergency standby applications, because historically utility service providers would not allow it (or had requirements that made it economically unfeasible), and it was considered to be a risk to reliability, since the ideal connection point for a utility parallel system is at the service entrance, and the ideal interconnect point for emergency equipment is close to loads. However, with the advent of the “smart grid” and the need for economic use of distributed generation equipment (especially synchronous machines) and the desire by customers to have an imperceptible transition from normal power to generators and back, utility paralleling is more important. Utility paralleling demands the use of equipment needed for that application and special efforts to coordination with the local utility/mains service suppliers.

7.2 Requirements and Recommendations

7.2.1 Requirements

- When dissimilar generator sets are used in a paralleling system, design work is required to include an analysis of the compatibility of the machines in the system to verify that the differences do not result in misoperation of the system or damage to the equipment. In general, engines, alternators, and especially load sharing control systems must be compatible to result in a successful application.

- Local utility approval is always required before on-site generation equipment is paralleled with the utility service.
- When using low voltage solidly grounded systems, there can be only one neutral to ground connection on any neutral bus. This leads to the recommendation for 4-wire low voltage paralleling systems to have the neutral to ground bond in the switchgear.
- For ground fault protection of equipment in low voltage systems, the ground fault sensing must be downstream from the neutral to ground bonding point.
- Dissimilar generators must have compatible engines, alternators, controls, and load sharing systems for successful paralleling.
- Alternators in paralleling applications should all have 2/3 pitch design.

7.2.2 Recommendations

- When existing generator sets, ATS, or switchboard/switchgear equipment is used in a system upgrade, it should be evaluated as to its condition and reliability, and tested under load prior to moving forward with the upgrade.
- When paralleling to the utility/mains service, it is desirable to use a 3-wire connection. If a 4-wire connection is used and switching from normal to generator source is required, consideration should be given to switching the neutral with a maximum 100 mS overlap.
- When considering the feasibility of a paralleling system upgrade, always be sure that the existing equipment is in good operating condition.
- If a system will be paralleled to the utility, permission from the local utility service supplier is required.

7.3 Grounding, Bonding, and Ground (Earth) Fault Systems

General considerations for selection of the grounding/earthing design for a facility are covered in Section 5.6 on page 112. This material covers the use of the most common grounding arrangements in systems using on-site generator sets: solidly grounded low voltage systems, and resistance grounded medium voltage systems; and the application of ground/earth fault protection in these systems.

7.3.1 Low Voltage Solidly Grounded/Earthed Systems

On-site power systems that are not separately derived will use a common grounding electrode system with the utility distribution system. The generator set neutral cannot be bonded to earth/ground at the generator set, but rather will use the neutral grounding provisions at the facility service entrance. Warning labels must be added to the service entrance switchboard to indicate that the on-site power system utilizes this grounding point, so that it is not inadvertently disconnected while the generator system is running. See the figure below for typical grounding and bonding arrangements for a system of this type.

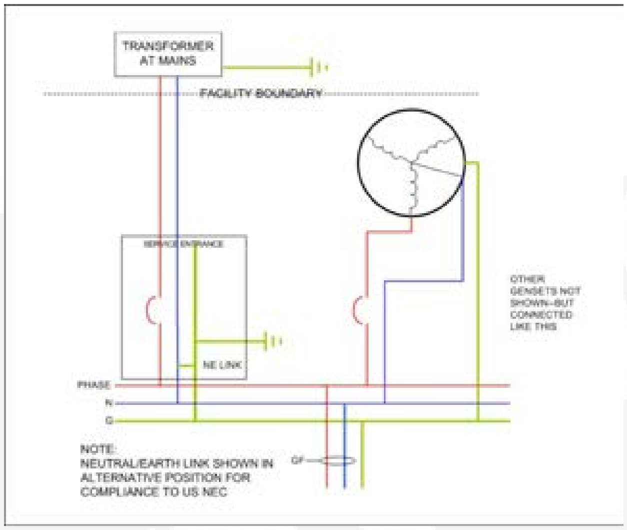


FIGURE 87. GROUNDING/BONDING/EARTHING PRACTICE FOR A TYPICAL COMMON BUS PARALLELING ARRANGEMENT. THIS DESIGN IS STANDARD FOR IEC ARRANGEMENTS AND OPTIONAL IN U.S./NEC APPLICATIONS, AND USED AS STANDARD PRACTICE IN THIS MANUAL.

If the facility distribution system incorporates ground fault protection equipment on both the service and feeder level and uses multiple automatic transfer switches (low voltage application), or if the distribution system utilizes no neutral connection, it will be necessary for the on-site system to be bonded to ground/earth at the generator set location also.

Low voltage, separately derived paralleling systems can utilize several different grounding designs. See **Figure 88** for grounding arrangements that may be used. See **Figure 89** for an alternate method of grounding the system. This is not a desirable design, because there are two neutral to ground points in the system, current can flow over the ground (voltage differential), resulting shock hazard. The medium voltage section of this manual covers grounding provisions for systems operating at over 600 VAC.

Note that in **Figure 88** the generator sets in the system are treated as a single large power source. Because there is a single grounding point (rather than individual grounding at each generator set, **Figure 89**) the ground fault current is easier to accurately sense than if each generator set were individually grounded. (The ground fault sensor is applied around the neutral to ground link.) If multilevel ground fault sensing is desired, feeder breakers can include either integral ground fault tripping arrangements or ground fault sensor and alarm equipment.

When paralleling equipment is used for emergency applications, it is strongly recommend to use only ground fault alarm indication, to enhance overall system reliability by preventing nuisance trips of the ground fault equipment on the emergency system. Where protection of the switchgear from an internal fault is desired, bus differential protection is more effective than ground fault sensing equipment. Switchgear constructions are available with provisions and testing/certification to minimize internal damage on an internal line to ground fault.

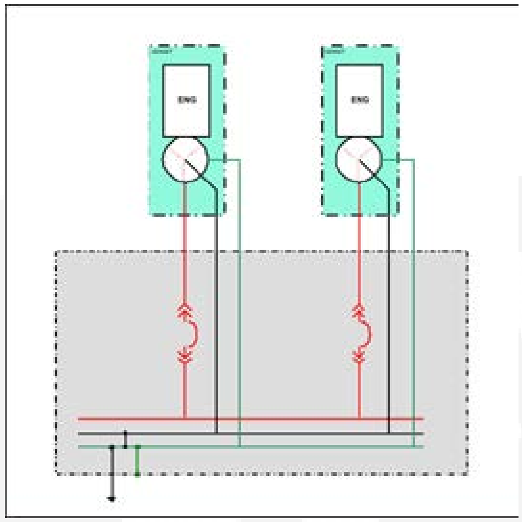


FIGURE 88. GROUNDING/EARTHING AND BONDING ARRANGEMENT FOR A TYPICAL SEPARATELY DERIVED SYSTEM USING 2/3 PITCH GENERATOR SETS. ALL THE METAL PARTS OF THE GENERATOR SET ARE BONDED TOGETHER, BUT ALL THESE BONDS ARE NOT SHOWN IN THIS DRAWING (AND THE OTHERS IN THIS SECTION), FOR SIMPLICITY.

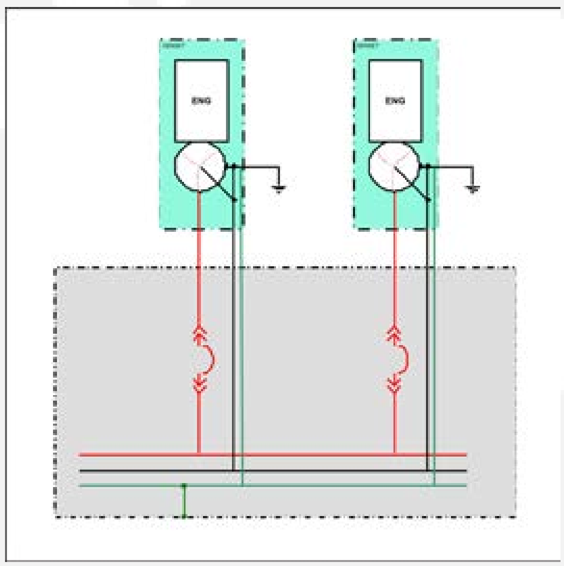


FIGURE 89. GROUNDING/EARTHING AND BONDING ARRANGEMENT FOR A SEPARATELY DERIVED SYSTEM WITH THE CONNECTION TO GROUND/EARTH AT EACH GENERATOR SET. THIS DESIGN IS COMMONLY USED, BUT TECHNICALLY FLAWED, SINCE TWO (OR MORE) BONDING POINTS ARE IN THE SYSTEM, RATHER THAN ONE.

Evaluation of a specific system for proper grounding and ground fault protection can be difficult. The many potential paths for ground fault current to flow make it difficult to determine whether sensing will be defeated by unexpected current paths. The problem can be addressed by applying two simple rules that must be followed if the system is to properly operate with conventional ground fault sensing equipment:

- There can be only one neutral to ground bonding connection on any neutral bus. The neutral can be switched, but only one connection should be in place at any point in time, except when doing a closed transition transfer between sources.

- The ground fault sensing equipment (when used) must be “downstream” from the neutral bonding point.

There are a few common exceptions to these rules that are allowed by some regional codes, such as in “main-tie-main” switchboard configurations, but even when the exception is allowed by code, the ground fault system is still impacted. Violating either rule will cause sensing issues or safety hazards, even when they are only violated for a short period of time, such as in fast (100 mS) closed transition transfer between sources. Sensing issues can be addressed by modifying the ground fault system to enable and disable sensors depending on the open/closed status of specific breakers in the system. However, these systems are complex (thus being difficult to commission and service) and expensive, so should be avoided when possible.

A consequence of this is that if a system incorporates utility (mains) paralleling, special arrangements are needed to properly manage system grounding so that there is always a neutral connection when current is flowing to the load, but never more than one, except for a very short (100 mS or less) overlap time period. Because of the dangers of operating without a neutral connection when it is required, a neutral switching system should be monitored for proper operation. A common practice would be to use “fail to open or close” and “contact failure” alarms in a fashion similar to that described for breaker misoperation in **Section 6.8 on page 194**.

Some designers address this issue by eliminating the neutral bus at the “top” switching point in the system (in other words, using a 3-phase/3-wire source), and utilize transformers to generate needed neutral connections downstream in the system where they are needed. In some applications this can reduce system cost by reducing the number of conductors to be installed at a site.

The type and location of ground fault equipment is a major driver in the design of the system with respect to grounding and bonding. It should be noted that North American system designs are more impacted by ground fault equipment than systems required to meet IEC requirements, because North American systems are commonly required to include ground fault at or near the sources, while IEC systems usually require ground fault protection further down in the electrical system.

In situations where the sources must be provided with ground fault protection and where multiple sources are connected to a common bus, ground fault detection rules should be applied with the understanding that the source of power to loads is not the utility or individual generators, but rather the bus that connects these sources together. In this case, ground fault protection or alarms are applied on bus feeders rather than on source breakers. This allows ground fault devices to be set to trip quickly and still be coordinated, and eliminates concerns for designs to prevent circulation of ground fault current through undesirable paths in a system. Since ground fault system design requirements are often driven by local codes and standards, consultation with the Authority Having Jurisdiction prior to construction is advisable.

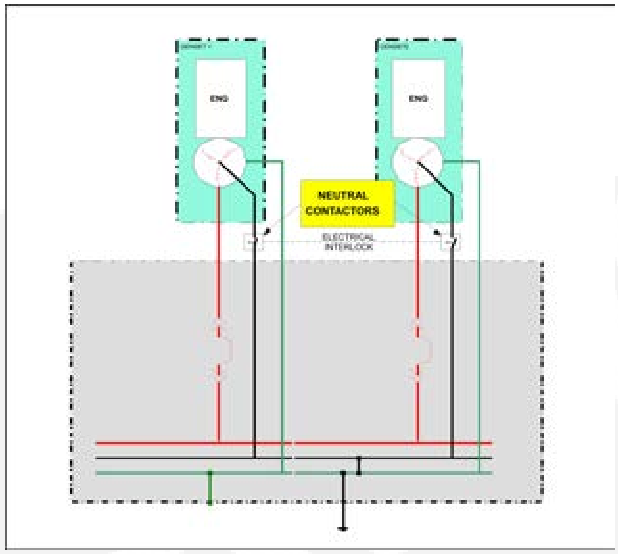


FIGURE 90. GROUNDING/EARTHING AND BONDING ARRANGEMENT FOR A TYPICAL SEPARATELY DERIVED SYSTEM USING NEUTRAL CONTACTORS. IN THIS ARRANGEMENT THE FIRST GENERATOR SET TO CLOSE TO THE BUS WOULD CLOSE ITS NEUTRAL CONTACTOR, AND THE SECOND WOULD REMAIN OPEN, SO THAT THE NEUTRAL POINTS OF THE GENERATOR SETS WOULD NOT BE TIED TOGETHER. THIS ARRANGEMENT IS LESS COMMON IN NORTH AMERICA THAN IN OTHER PARTS OF THE WORLD.

Facility power distribution systems will usually have a single neutral connection point ground/earth on each contiguous neutral bus in the system. In a paralleling application using neutral contactors (see Figure 90) the first generator set that closes ties neutral to bus. The second and subsequent sets will not close their contactors. On utility parallel closed transition transfer best practice is to do a fast (approximately 100 mS) overlap between connection of generator set and utility ground (see Figure 91). Utility grounding point is at service entrance.

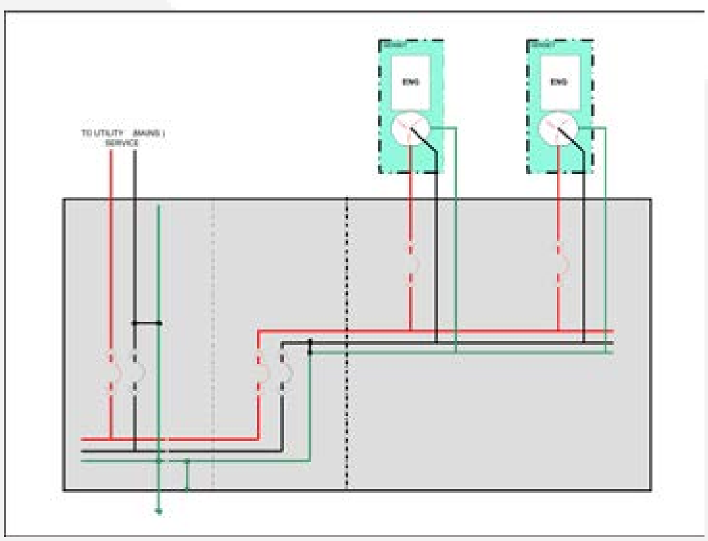


FIGURE 91. GROUNDING/EARTHING AND BONDING ARRANGEMENT FOR A TYPICAL SEPARATELY DERIVED SYSTEM USING 4-POLE BREAKERS IN A TRANSFER PAIR TOPOLOGY. EACH SOURCE (UTILITY/MAINS SERVICE AND GENERATOR BUS) MUST BE BONDED TO THE GROUNDING ELECTRODE SYSTEM, BUT ONLY ONE NEUTRAL CAN BE CONNECTED AT ANY POINT IN TIME.

Generally, the situation in Europe is the same if neutral earthing contactors are used as described above.

The alternative system which is also used quite extensively is to allow all generators to close with coupled neutrals. This can be done provided the machines have 2/3 pitched windings. This system has the advantage in that it is simpler from the point of view of control, but can run into trouble on high voltage machines fitted with neutral earth resistors in that the machines must be disconnected completely before working in any of the high voltage terminal boxes. Therefore the system has to be shut down. Refer to section 5 of T-030 for more details.

7.3.2 Grounding Resistors

Due to inherent design characteristics of on-site generator sets, the zero sequence reactance of the generator is often significantly lower than the positive sequence reactance. Therefore, the generator set can produce considerably higher levels of fault current to a single-phase fault than to a three-phase bolted fault. Although low voltage generator sets are braced for these fault levels, many medium voltage generator sets are not. Also, a line to ground fault can cause an over voltage condition at the generator set which can damage alternator insulation[3]. Consequently, for a designer preparing a general facility design with medium voltage generator sets, it is considered good practice to include grounding resistors for the generator set so that fault currents are reduced to a level that is suitable for the generator bracing design[4]. Grounding resistors are also used on low and medium voltage applications where service reliability is critical and loads are 3-wire, such as in process control applications where failure of service is economically catastrophic.

Low resistance grounding equipment is often specified for this purpose. The objective of a low resistance grounding system is to reduce the fault current to not more than approximately the rated output of the generator set in amperes. To achieve this goal for a 4160 volt system, a grounding resistor rated for 2400 volts for 10 seconds would be specified.

On-site generator sets (or systems) can also be provided with high resistance grounding equipment. The higher impedance to current flow allows ground fault current to flow for a longer time, so that the source of the problem can be isolated, rather than dropping the entire system off line.

Grounding resistors are physically large. Configurations are available for mounting them in free-standing enclosures, either inside or outside a building or on the top of the switchgear for the generator set paralleling breaker. A high resistance ground system will typically have ratings of 2400 volts at 6-10 amps for an infinite time period.

Note that in the case of a low resistance ground designed for protection of the alternator, the grounding resistor is often specified to operate only for a limited amount of time. Protective relaying is provided to shutdown the generator set (or system) if a ground fault continues for more than 10 seconds (or the time setting of the protective device). In critical applications, it may be desirable to design the system to operate continuously with a ground fault applied to the system and rely on downstream protection to isolate the fault.

Cummins Power Generation low and medium voltage alternators are braced for the level of single phase fault they produce so are suitable for application without a grounding resistor if desired by the system designer.

[3] Cummins Power Generation alternators provided with PowerCommand controls are provided with a fault current regulation function that prevents overvoltage conditions on a line to ground fault

[4] Cummins Power Generation low and medium voltage alternators are braced for the level of single phase fault they produce, so are suitable for application without a grounding resistor if desired by the system designer

7.3.3 Neutral Grounding Methods - 5/15 kV

Generator sets of 5 kV may be used in distribution systems that are ungrounded, solidly grounded, or resistance grounded. However, not all 5 kV generator sets are braced for the effects of a single phase fault, so it is common practice to provide neutral grounding resistors for medium voltage generator sets. These have the advantages of:

- Limiting the magnitude and damage level of ground faults (especially where ground fault tripping is undesirable).
- Limiting the magnitude of voltage excursions due to line-to-ground faults.
- Providing enhanced protection to the generator set, by limiting the magnitude of the single phase fault current. The reduction in current level reduces stress on windings due to magnetic effects and reduces the internal heating of the generator on a fault.

With a paralleled generator system, the generator sets may be individually grounded through a grounding resister or may be tied to a common ground point with a single grounding resistor.

The major advantage of a multiple ground design is that the current level that returns to each set is closely controlled. Another advantage of the multiple ground design is that, because the neutrals are not connected together, there is no possibility of a potential between neutral and ground on a non-operating machine, as there would be with a common neutral grounding point.

The advantage of a single ground point and single resistor is that (1) some cost is avoided and (2) the system ground current level is more clearly specified and known. (Theoretically it could be set at a higher current level, so the fault would be easier to detect.)

When neutral grounding resistors are used, the magnitude of current flow, and the duration of current flow must be specified. The higher the current level, and the greater the time, the higher the cost of the resistor becomes. However, the higher the current level, the easier it is to accurately detect the ground fault condition.

7.3.3.1 Selecting Grounding Resistors

The three electrical ratings required to select a grounding resistor are: voltage rating, current rating, and time rating. Resistor ratings are defined by IEEE Standard 32.

IEEE standards specify:

- 10 second, 760 degree temperature rise;
- extended time, and 610 degree temperature rise;
- continuous, 385 degree temperature rise.

Grounding resistor specifications include the following parameters:

- Voltage Rating: The Grounding Resistor Voltage Rating is based on the system phase-to-neutral voltage. This voltage can be calculated by dividing the phase-to-phase voltage by √3. (√3 = 1.732).
- Current Rating Resistance: Grounding falls into two categories: Low Resistance and High Resistance. In Low Resistance Grounded Systems the current is limited to 25 amps or more. Generally the range is from 25 to 600 amps and is commonly 1-1.5 times the generator rating, although in some systems it may be even greater. In High Resistance Grounded Systems the current is limited to 10 amps or less.
- Standard Time Ratings: Ten Seconds, One Minute, Ten Minutes, and Extended Time. The time rating indicates the time that the grounding resistor can operate under fault conditions without exceeding the specified temperature rise above a 30 ˚C ambient.

- Temperature rise:
  - For resistors with a rating of less than ten minutes - 760 ˚C;
  - For resistors with a ten minute and extended time rating - 610 ˚C;
  - For steady-state operation - 385 ˚C.

In order to insure normal life of an extended time rated device, it must not operate at its maximum temperature rise for more than an average of 90 days per year.

7.3.3.2 Resistor Application Considerations

Resistance grounding is often recommended on medium voltage emergency/standby systems from 1000 volts to 15,000 volts phase-to-phase primarily for the purpose of protection of the alternator from the effects of various faults.

Because of the cost, Resistance Grounding is not usually used on systems above 15,000 volts phase-to-phase. Additionally, the use of a solidly grounded system allows for use of equipment which is insulated for the phase-to-neutral voltage of the system.

When a system has protective relays which will trip the circuit if a ground fault occurs, a grounding resistor with a 10 second rating is often specified, because the relays will trip the system in less than 10 seconds. However, one minute or ten minute ratings are sometimes used for an extra margin of safety, even though the cost will be greater.

The extended time resistor is normally used when it is necessary to let the ground fault persist for some time. An example of this would be in the refining industry where it is very costly to shut down in mid-process. Therefore, the grounding system is designed to limit the ground fault current but does not shut down the system when the fault occurs. In a situation such as this, a method of indicating a ground fault will be used, such as lights or alarm annunciation, but the fault will not be cleared until an orderly shutdown can be planned.

When protective relaying is required for operation of the protection system, the grounding resistor assembly should be provided with mounted voltage and current sensor devices.

7.3.3.3 Installation of Grounding Resistors

Grounding resistors are available for either indoor or outdoor installations. Indoor installations are considered to be more reliable because they provide protection against deterioration of the equipment due to environmental extremes.

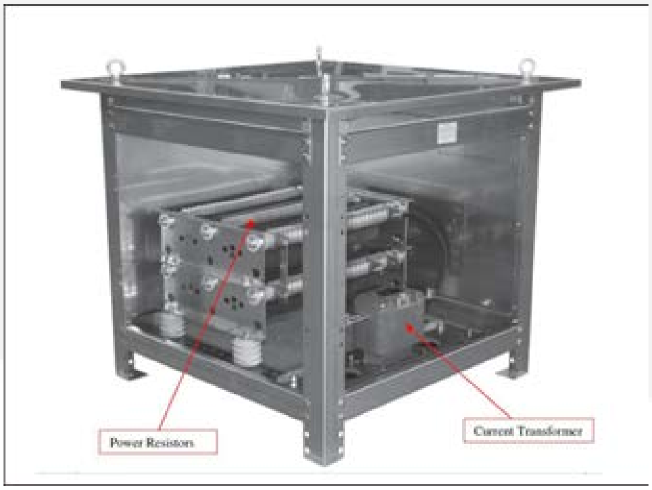


FIGURE 92. TYPICAL NEUTRAL GROUNDING RESISTOR.

Grounding resistors are available with open construction, or either a louver or screen type enclosure for indoor mounting. Open construction is suitable for situations where the resistors are protected from the elements and not accessible to human contact. In this configuration they may be mounted on the top of switchgear or in switchgear or transformer compartments. Use of screens provides for better heat flow, but the louver design provides better physical protection for the resistor element and better protection for personnel working in the vicinity of the equipment. Outdoor enclosures typically include solid side covers and elevated hood. This gives a level of protection against ingress of rain, sleet, and hail, with acceptable ventilation. Elevated stands can be specified to help in mounting of the equipment.

Enclosure should be constructed of heavy gauge cold rolled steel, and a baked enamel finish is desirable. All mounting hardware should be stainless steel.

When they are in service under fault conditions, considerable heat is generated, so this should be considered in the design of fire sensing and protection equipment.

7.4 System Upgrades and Additions

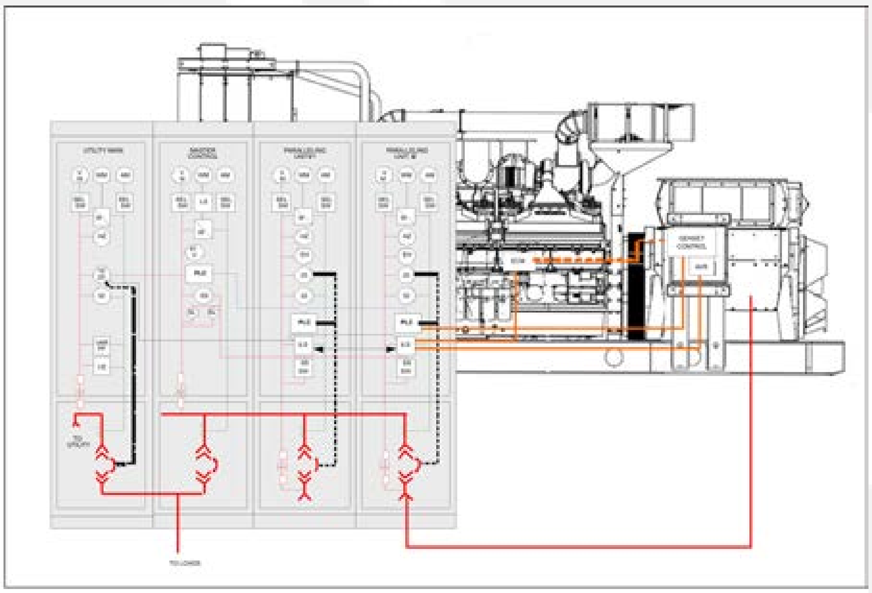


FIGURE 93. A TRADITIONAL PARALLELING SYSTEM (ONE GENERATOR SET ONLY SHOWN), WITH REMOTELY MOUNTED PARALLELING CONTROL EQUIPMENT. CONTRAST TO FIGURE 94 BELOW, WHICH SHOWS THE SAME CONTROL FUNCTIONALITY USING INTEGRATED PARALLELING CONTROLLERS.

Emergency/standby power systems are different from most other facility infrastructure in that it is normally not in operation and not energized (other than at power transfer equipment). Consequently, even after 20 years of service, it is not uncommon for the system to have had fewer than 500 hours of operation. Much of the system, particularly the generator set engines, is essentially “like new” if it has been properly maintained.

Also, facility needs change over time, and expansions and additions are common. When a change requires increased capability in the emergency/standby power system, it is only reasonable to consider upgrading the existing system rather than starting again with completely new equipment.

It is also important to understand physically where the new equipment will need to be installed relative to the old equipment.

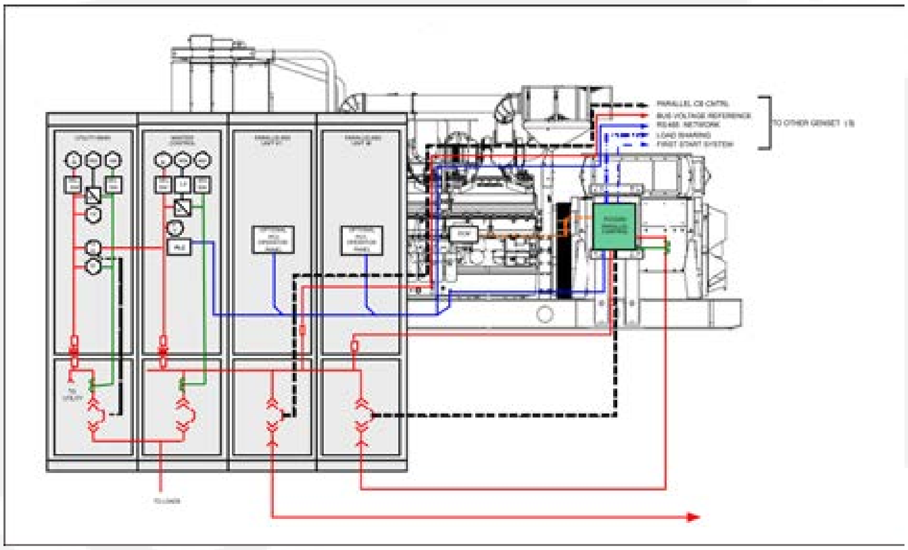


FIGURE 94. INTEGRATED PARALLELING CONTROLS USED TO UPGRADE EXISTING SWITCHGEAR EQUIPMENT. NOTE THAT THE CORE SWITCHGEAR STRUCTURE IS UNCHANGED, BUT LITTLE OR NO CONTROL SPACE IS NEEDED FOR PARALLELING FUNCTIONS.

7.4.1 System-Level Issues

To a limited degree, systems can operate successfully with less than completely compatible equipment, but these incompatibilities may result in the need for added equipment in the system or limitations in the flexibility or operation of the system.

If generator sets are of dissimilar sizes, there can be impacts on the system design. An emergency system with generator sets that have matching kW ratings can support a higher first priority load than a system that has generator sets with dissimilar kW ratings.

For example, an emergency system with two 500 kW generator sets will handle a first priority load as large as 500 kW. A system with one 750 kW generator set and one 250 kW generator set, while having the same total power rating, should be limited to a 250 kW first priority load, because if the first generator set closing to the bus is the 250 kW machine, any load greater than 250 kW could cause it to be overloaded.

Changes in sequence of operation may be necessary due to use of dissimilar-sized machines when the smallest machine in the system cannot pick up the entire first priority load, since it is not advisable to design a system sequence of operation contingent on synchronizing generator sets within 10 seconds. Many manufacturers cannot provide equipment that is certain to be paralleled in 10 seconds, so in situations where local codes require service to emergency loads within 10 or 15 seconds, the system designer must choose between preventing smaller machines from closing to the bus first (minimizing the advantage of redundancy offered by many systems), or making sure that first priority loads can always be served by the smallest machine in the system.

When faced with the problem of first priority loads that exceed the capacity of one or more of the generator sets in a system, it is possible to insert bus isolation ties between generator sets in order to prevent overloading on startup. This, however, sets up another series of issues because of the added complexity in the sequence of operation and usually the need for more synchronizers in the system. Manual operation and failure mode effects prevention are also more difficult to deal with as tie breakers are inserted into a system.

From a load shed perspective, the problem is less difficult, but still needs a bit of thought. If there is an under-frequency condition on the bus, the system will need to drop load. With dissimilar-sized machines, it is desirable to drop load in large enough steps to relieve the 250 kW set in the event that the 500 kW unit becomes the unit that is not available. Cascading type load shedding systems continue to drop load until the system recovers, so they automatically deal with the problem via that mechanism. A system design that “knows” the kW capacity of the generator sets available on line can automatically compensate for the difference in sizes by using different sequencing when different combinations of equipment are available.

How much difference in size is “practical”? That is a matter of considerable discussion in the industry. We know that it is technically possible to parallel anything with anything, but where it is practical is less clear.

In general (for emergency/standby applications), you probably will have a manageable system when the smallest generator set is no less than 30% of the capacity of the largest generator set in the system. If there is a larger disparity in equipment sizes, it might be easier to make the larger machine bigger, and forget about paralleling altogether.

It is useful to note that there are often large kW size differences in prime power applications, such as are used in remote, isolated cities and towns. In those applications, loads during the daylight hours are often much higher than in the evenings. A pair of 350 kW generator sets may be running during the day, and only a 50 kW set running at night. This is less of an issue in prime power applications because the load profile does not quickly change, and the systems generally have no automatic load management systems.

As a technical matter, the smallest power circuit breaker that is commercially available at low voltage is an 800 amp frame. So it can be costly to parallel smaller generator sets. In those cases it is possible to source some 5-cycle operating molded case breakers for use in paralleling the generator. These breakers are smaller, available in fixed frame configurations so less space is needed for the equipment, and less expensive, but they are available only from a limited number of suppliers.

In some cases motor starting contactors might be used for paralleling applications where smaller generator sets are used, but the contactors must generally be protected by current limiting fuses for a safe design.

7.4.2 Existing Equipment Conditions

Before any modifications to any existing system are made, it is critical that the equipment to be modified is fully tested to verify that it can operate at full rated load with proper voltage and frequency control. If a machine cannot perform properly with a dedicated load from a load bank, there is no way that it will operate successfully in parallel with other machines.

7.4.2.1 Generator Sets

The first order of business is to determine the condition of the existing generator set equipment:

- Are the generators in good operating condition?
- Have they been properly maintained?

- Are test reports available that verify proper performance?
- Perform functional tests of generators, including full load testing.
- Is the existing switchgear usable?
- Are there records documenting good maintenance through the life of the system?
- Are the equipment ratings appropriate for new needs? (Such as switchgear bus ampacity and bracing.)

In any event, plan to perform functional tests of the individual generators, including full load testing of each generator set to verify that it carries rated load and picks up load properly by performing quarter load step block load testing. The generator sets should carry load at all load levels within their rated voltage and frequency levels, and transient performance must be within their normal operating ranges. If all the equipment performs properly, then the project can proceed. If not, then the equipment must be repaired and retested prior to starting conversion work. It is good practice to document all the testing done, and adjustment of governor and AVR gains to achieve similar transient performance is desirable.

Care should be taken to verify fuel system design and operational capability, particularly if new generator sets are added to the system, since the fuel system design is somewhat engine dependent and new engines tend to have more stringent fuel system requirements than older engines.

It is not necessary to test the generator sets in parallel, since all the paralleling controls are generally replaced as a part of the conversion process. Parallel system testing will be necessary after all the conversion work is completed on a project as a part of the system commissioning process.

7.4.2.2 Switchboard/Switchgear/ATS

If the existing switchgear is planned to be re-used, then it also must be inspected and tested to verify that is suitable for use with the generator sets. While bus structures and sheet metal are not likely to be a significant issue, many parts of the switchboard/switchgear equipment need to be evaluated. Consideration should be given to:

- What environment has the switchboard/switchgear equipment been in? If it has been in a humid or outdoor environment there is a greater probability that the equipment needs service or adjustment.
- Has the equipment been properly maintained? Has it been kept clean? Tested regularly? What are the results of that work?
- Are there spare parts and service technicians available to maintain and repair the equipment should there be failures?
- Is the equipment fully operational and reliable prior to the start of work?
- Are the ratings appropriate for planned system as it is to be revised? (bus ampacity and bracing are critical)

Many switchboard/switchgear components have a finite life, even relative to the facility life and in a good environment.

For example, insulation on electrical coils of various types such as might be used in relay coils, trip coils, etc. are potentially suspect if they are more than 20 years old. Insulation on conductors also can age with time. Inspection/testing of all these devices is advisable prior to performing a system upgrade.

Molded case circuit breakers, even if they have not operated during fault or overload conditions begin to degrade over time. Trip characteristics tend to be delayed, making it possible that downstream devices may be damaged if a fault occurs. In general, these devices can not be serviced, so if they are tested and do not operate properly, they will need to be replaced. If molded case breakers are used in switch duty applications, and have been subjected to more than 200 operations, they should be replaced.

Power circuit breakers, including insulated case breakers and power air circuit breakers are more repairable, but are also more complex. Again, even if they have not be operated due to fault or overload conditions, natural aging of internal components may make them susceptible to unexpected failure under normal operating conditions. Any power circuit breaker more than 15-20 years old should be inspected and tested to verify that it is fully operational. Consult the breaker manufacturer for recommendations of specific parts that need to be changed to maintain breaker reliability.

Protective relaying should be calibrated and tested to verify proper operation. Induction disc relaying should be replaced with microprocessor-based protective devices. Any generator set protection can probably be eliminated and functionally replaced by protection inherent in a generator set control.

Control systems of any automated switchboard/switchgear system should be evaluated and tested in a similar fashion to other equipment to verify proper operation, and also to verify that service parts and service technicians are available to respond to a failure in that part of the system.

If the system level controls and monitoring equipment are operational and serviceable, the paralleling functions only may be done; as long as adequate accurate documentation is available to interconnect the systems. If the existing system level controls are not operational or serviceable, or they have questionable reliability, they can be replaced by off-the-shelf system level controllers from some suppliers.

7.4.3 Paralleling Dissimilar Generator Sets

As a general rule, “you can parallel anything with anything,” as long as the voltage and frequency are the same at the point of interconnection. Of course, there are practical limits to this statement, and a design requiring reliability and performance may compel a system designer to replace existing generator sets when they cannot be verified to be compatible with newer equipment, or if the costs of driving compatibility into the older equipment are not justified.

Simply speaking, generator sets in a paralleling system are compatible when they have:

- Compatible engines
- Compatible alternators
- Compatible load sharing control systems
- Compatible interfaces to other monitoring and control systems, including local and remote monitoring, “first start” controls, manual controls, and load demand controls

Questions to ask about a paralleling retrofit:

- Does the existing system work properly? In other words: Do all the units load share real and reactive load proportionally? Sequence correctly? If the generator sets are not working prior to conversion, it is unwise to go into the project without considering the potential costs of fixing all the existing issues.
- What are the existing generator set model and serial numbers? Engines? Alternators?

- Is there data from regular exercise/testing of the system to document capability?
- What is the pitch of the alternator? Does it incorporate a PMG? If not 2/3 pitch, plan an alternator change out or other provisions necessary for compatibility with the new generator sets.
- What model and serial number of generator set governor? This is needed to verify what type of signal is available for operation of the engine fuel rate actuator, or if there is a speed bias signal available.
- What model and serial number of AVR? This is necessary to understand what signal is going to the alternator field and what type of load sharing/reactive load governing capability will need to be used.
- Can we have a set of drawings for the existing system, and for all the components of the system? If the answer to this is no, a retrofit project is very risky, because it will be difficult to verify details of system operation and wiring.

7.4.3.1 Compatible Engines

The real power (kW) provided by a generator set operating in parallel with others is a direct function of engine real power output. Compatible engines can share load nearly equally, at all load levels, while operating at steady state load levels and during transient loading conditions.

Conversely, if incompatible engines are paralleled, load sharing problems can occur, particularly on application and especially on rejection of large load steps.

As loads are added to a generator set, particularly in large increments, the generator set frequency will momentarily drop until the engine governor can drive more fuel into the engine to recover to its nominal speed (frequency). The amount of speed drop and the recovery time are a function of the inertia in the rotating components of the system and how fast the governing and air intake systems can increase the air/fuel mixture in the engine. The generator set's recovery rate is determined by the type of governing system, the engine's fuel and air intake system designs, and the engine's combustion cycle (two-stroke or four-stroke).

Load sharing during transient conditions is a concern because differently sized machines often accept and reject load with different levels of ability. For example, consider a paralleled 250 kW and a 500 kW generator set. Application of a 250 kW load on a 250 kW generator set will result in a voltage dip of approximately 25%, and a recovery time of 3 seconds. For the 500 kW generator set, a 500 kW load results in a voltage dip of 30%, and a recovery time of 5 seconds.

So, if a 750 kW load (a full load step) is applied on the two machines, or drops 750 kW in one step from the two machines, they will not share loads equally during the transient period. It is possible to have the system exposed to potential overcurrent conditions on the faster machine or nuisance reverse power faults on load rejection. Protection settings may require adjustment to prevent nuisance tripping.

At lower load levels, voltage and frequency transients are lower, and recovery times are shorter, so as load step size drops, it eventually gets to the point that transients of a specific level are very similar between machines. This means that dissimilar transient performance of the machines can be dealt with by adding and shedding loads in smaller steps than might be used in a system that has all the machines of the same size. A system designer can compare the single step load pickup and load rejection performance of the various machines in the system to determine if there is a potential problem with engine compatibility. When that is done, actual assembled generator set test data should be used in the evaluation, not just alternator voltage dip or engine (alone) transient performance. As a general rule, there will be no negative impacts due to difference in engine performance if the transient load steps are less than 25% of the rating of the smallest generator set in the system. Nuisance reverse power trips on load rejection can often be addressed by increasing the time delay on reverse power to outside the recovery time for the slowest machine in the system. Do not address the issue by increasing the "Reverse Power" limit on the generator set. This could desensitize the system to the point that reverse power protection is lost.

7.4.3.2 Compatible Alternators

Paralleled alternators are compatible if they can operate in parallel without having damaging or disruptive neutral currents flowing between them. The magnitude of harmonic current flow related to the dissimilarity between paralleled sets depends upon the shape of their voltage waveforms. Depending on the generators' temperature rise characteristics, age and insulating ratings, neutral current flow between generator sets is not necessarily damaging. Be aware that neutral currents can also cause disruption in protective relay operation, particularly for ground fault sensing.

7.4.3.2.1 Voltage Waveforms Harmonics

The voltage waveform shape created by an alternator when operating unloaded or driving a linear load may be described in terms of its fundamental frequency and voltage magnitude and the magnitude of the harmonic voltages and their frequencies. The description is necessary because all alternators exhibit some level of harmonic voltage distortion, and while these distortions are very small relative to the distortion that can be caused by non-linear loads, they may still be significant, particularly in paralleling applications.

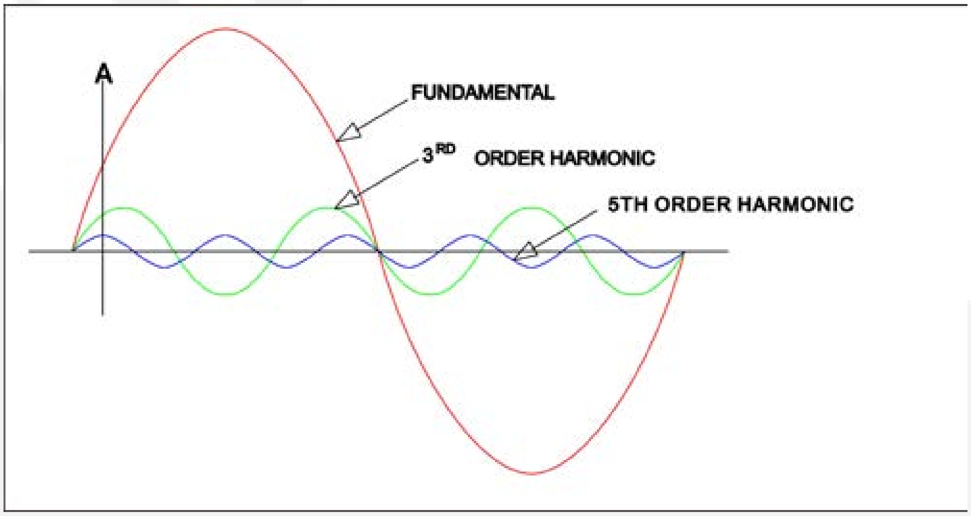


FIGURE 95. FUNDAMENTAL AND HARMONIC VOLTAGE WAVEFORMS.

Figure 95 shows the relationship of first-order (fundamental frequency waveform) to third and fifth-order harmonic waveforms. The harmonic voltages are effectively added to the fundamental waveform, resulting in the pure sinusoidal shape of the fundamental being somewhat distorted. For example, the resultant voltage at time A in this figure will be the sum of the blue (fifth-order), green (third-order), and red voltage magnitudes. So, the instantaneous voltage at that instant in time would be somewhat higher than the voltage of the fundamental. Note that the illustration greatly magnifies the typical magnitudes of harmonic voltage levels to more easily show the principles surrounding this discussion.

No alternator manufacturer intentionally inserts harmonic voltages in its designs, but some magnitude of distortion is inevitable due to the physics and practical limitations of AC machine design. During the design process the alternator designer will attempt to design the machine to minimize the voltage distortion (i.e., the magnitude of the third- and higher-order harmonic voltages), while minimizing the cost of the machine at a specific rating. The differences in the overall waveform shape of dissimilar machines are at the heart of problems generated by the paralleling of these machines.

7.4.3.2.1.1 Mechanical Design Characteristics Driving Harmonics

Alternator designers can control the magnitude and orders of harmonics produced in an alternator by manipulation of several design factors, the most important of which is alternator pitch.

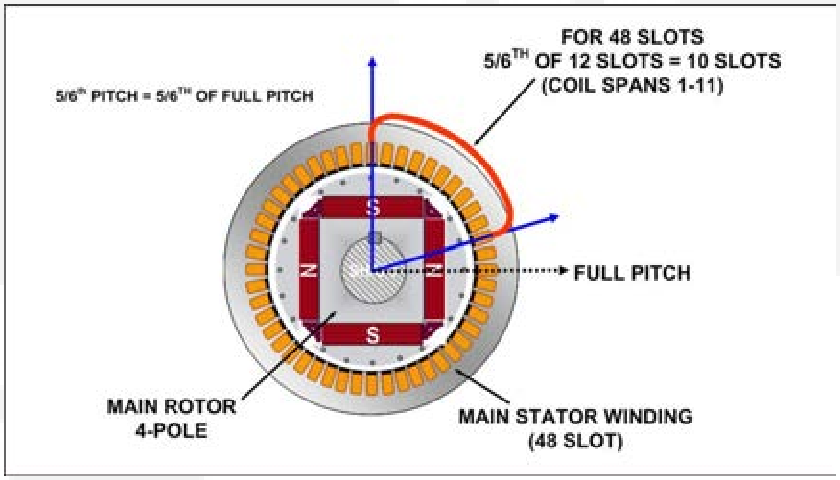


FIGURE 96. A 5/6 PITCH ALTERNATOR DESIGN WILL INCLUDE COILS THAT SPAN 5/6 OF THE STATOR SLOTS

Pitch is a term used to define a mechanical design characteristic of a generator. It is the ratio of the number of slots spanned by each coil in the alternator stator to the number of winding slots per generator pole. In the figure above (**Figure 96**), which shows a 4-pole machine with 48 total slots, there will be 12 slots per pole, and since the coils span 10 slots, the alternator slot-to-coil ratio is 10/12, or “5/6 pitch.” In the figure below (**Figure 97**) we see an alternator winding that spans 8 slots, so with 12 slots per pole, that machine would be 2/3 pitch.

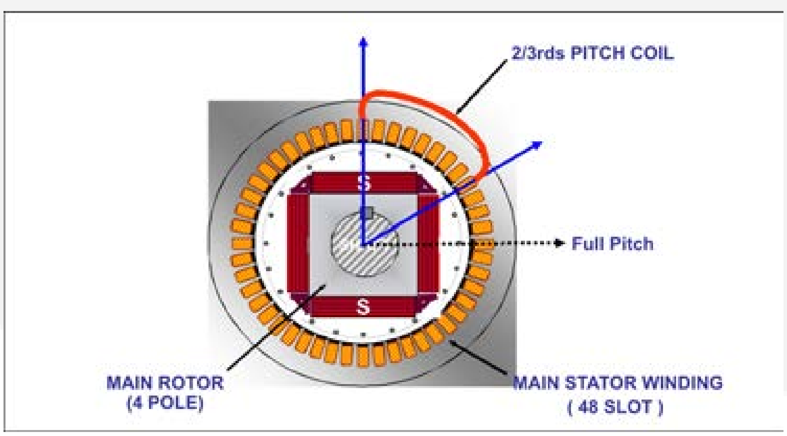


FIGURE 97. A 2/3 PITCH ALTERNATOR WINDING WILL SPAN 2/3 OF THE POLES IN THE ALTERNATOR STATOR.

The pitch of a generator is a design parameter that can be used to optimize the generator waveform shape and minimize the generator cost, because shorter pitch (lower pitch ratios) use the alternator stator less effectively and require the use of more copper for the same kW output than higher pitch machines. For example, an alternator could be provided with a 2/3 pitch, which would eliminate third-order harmonics, but result in slightly higher fifth- and seventh-order harmonics. Alternately, the alternator designer could select another pitch design, which usually would result in high levels of third-order harmonics, but relatively lower levels of fifth- and seventh-order harmonics, and probably a bit more kW capacity for the materials used in the machine. For example, a 5/6 pitch machine illustrated would have relatively lower fifth- and seventh order harmonics, but much higher third-order harmonics and lower cost.

In general, the odd-order harmonics are of the greatest concern to a system designer, because they will have the greatest impact on the operation of loads and on extraneous heating effects in the power supply and distribution system. Third-order harmonics (and their multiples) are problematical because they directly add in the neutral, and can result in large neutral current flows between paralleled machines. They are also more problematic because they can migrate through the system across some transformer types.

Fifth-order harmonics (and their multiples) are considered to be a concern because they are “negative sequence” currents, and will cause some level of abnormal heating in rotating load devices. However, with careful design of a 2/3 pitch machine, the fifth- and seventh-order harmonics can be reduced to magnitudes of a level similar to higher pitch machines, leaving the major advantage of higher pitch machines to be exclusively lower initial cost.

For paralleling applications, it is highly desirable to utilize 2/3 pitch designs. Because no third-order harmonics are created by the machine, paralleling compatibility with utility (mains) sources or other 2/3 neutral currents related to third-order harmonics; and higher-order harmonics see relatively greater impedances at higher frequencies and are thus much less of a problem in terms of neutral current flow. The system designer should select alternators that not only have a 2/3 pitch design, but also have minimum fifth-, seventh- and higher-order harmonics.

A good standard to achieve for machines ranging in size from roughly 100 kW to 4 MW is that the machine should have not more than 5% total harmonic distortion at any load between no load and full load, measured line to line and line to neutral, and not more than 3.0 percent in any single harmonic level.

7.4.3.2.2 Circulating Neutral Currents Due to Alternator Differences

When generators are paralleled, the voltage of the two machines is forced to the exact same magnitude. Differences in voltage, regardless of their frequency, will result in current flow from the machine with higher instantaneous voltage to the machine (or machines) with lower instantaneous voltage. The figure below illustrates this phenomenon.

In **Figure 98**, two voltage waveforms (red and blue lines) are superimposed upon each other. Note that these voltage waveforms may be exactly the same RMS voltage magnitude, but at different points in time the blue voltage is higher than the red, and vice versa. When the machines are connected together on a common bus, the differences in voltage result in current flow between the machines, which is represented by the green line.

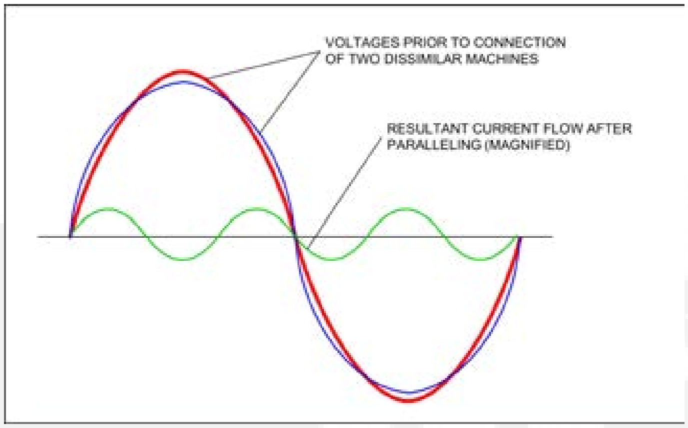


FIGURE 98. DIFFERENCES IN VOLTAGE WAVEFORM SHAPE BETWEEN TWO GENERATOR SETS WILL CAUSE HARMONIC CURRENT FLOW. IN THIS CASE, THIRD ORDER HARMONIC CURRENT IS FLOWING.

Note that in this simple example the magnitude of the current shown is exaggerated, again to more clearly illustrate the phenomenon. Note also that because the blue and red voltage lines cross each other three times in each half cycle, the current magnitude generated is a third-order harmonic current. So, at any point in the cycle where there is a voltage difference between the machines prior to paralleling, current will flow between the machines. This is referred to as circulating neutral current and is apparent when there is a path through the neutral of the system in which the current can flow.

The impact of incompatibility can be clearly seen with proper measuring devices, and is often visible with conventional AC current metering. The system will be most apparent by displaying current flowing from each generator with no load on the system. If neutral current is flowing at higher than 60 Hz (particularly 150 Hz in a 50 Hz system and 180 Hz in a 60 Hz system) with no load or a linear load applied to the system, alternator design differences are indicated.

Neutral current flow of 60 or 50 Hz is caused by misadjustment of the voltage or reactive load sharing a system of the generator sets in the system. (This is termed a “cross-current” condition.) This circulating current caused by alternator pitch differences is not adjustable by manipulation of crosscurrent compensation or other devices. Due to the difference in voltage waveform shape of the different alternators, circulating current is inherent in the system. The circulating current may or may not be damaging to the alternators, depending on the magnitude of the current, the ratings of the generators in the system and the susceptibility of protective devices in the system to harmonic currents. Because the harmonic content of a generator waveform varies with the load, the negative effects of operating with dissimilar generators may be more apparent at some load levels than at others, but typically the major concern will be the magnitude of current flow at rated load, because that is the point at which the internal temperature of the alternator will typically be highest and is most susceptible to failure.

A system designer can make simplifying assumptions to reduce this problem to a manageable level. Because harmonics higher than the third order in 2/3 pitch machines are not normally present at a level high enough to be damaging, the designer will typically consider only the third-order harmonic voltages. These are completely eliminated by using generators with 2/3 pitch winding design.

A 2/3 pitch is not required for successful parallel operation of generators. Other pitches may be used (and used in conjunction with 2/3 pitch machines), but their use may limit future system expansion flexibility or require other system measures to limit neutral current flow.

7.4.3.2.3 Compensating for Dissimilar Alternators in a System Design

When faced with a requirement to parallel dissimilar generators, a system designer has several options to avoid problems associated with generator incompatibility:

If possible, require that new or replacement alternator equipment be identical to existing equipment. This may or may not be practical depending on the voltage harmonics produced by the alternators in the existing system, especially if the machines are of significantly different kVA ratings. In machines other than 2/3 pitch arrangements; the fact that the machines are the same pitch may not be enough to eliminate problems, because differences in third-order harmonics could still cause significant neutral current flow. Where this is practical, it is probably the best solution. While this may sound like an extreme suggestion, it should be recognized that the alternator on a generator set represents only about 10-20% of the total factory cost of the machine, and that alternators do age over time regardless of their limited use in standby applications. It is prudent to replace an alternator when it is more than 25 years old as part of a paralleling upgrade in a system.

Use a three-wire distribution system. By avoiding a solid neutral connection between the generator set bus and the loads, the designer is free to let the neutral of the dissimilar machines in a system float, so that the most common cause of harmonic problems is minimized by removing the path on which the most disruptive current can flow. (The harmonic currents will still cause heating in the machines, but the disruptive effect of current flow in the neutral is eliminated.) In these systems, loads that require a neutral connection will be required to be served by a delta/wye transformer to develop the required neutral connection. The designer should carefully specify the neutral grounding design and monitor the installation in these systems, because an errant neutral-to-ground bonding will result in neutral current flowing through the grounding (earthing) conductors in the system, which represents a potential hazard for electric shock and for fire due to overheating of conductors. Downstream transformers can be used to provide four-wire service to loads that require it.

Connect neutrals of like-pitch machines only. Note that line voltage systems (those operating at less than 1000 VAC) are often designed to have a neutral-to-ground connection. In a parallel application the ideal location for this bonding point is in the system switchgear, so that there is only one neutral bond for the system. Consideration must be given to the magnitude of loads requiring the neutral connection versus loads that can operate only on the three phases. System loads will naturally balance out as long as there is sufficient line-to-neutral capacity in the system.

Add neutral contactors in the link between the generator sets and switchgear neutral bus to connect the neutral only on the first unit to close to the bus (**Figure 90 on page 208**). This has a similar impact to the previous recommendation, but allows any machine to be the first connected to the system. In this design it is particularly critical for the failure modes of the neutral contactors to be considered. Alarms should be raised by failure of a neutral closure to operate correctly in either opening or closing mode. Dual neutral contactor position indicating contacts (one “a” and one “b” from different switches) should be used to be more certain of the state of the neutral contactor.

Install reactors in the neutral leg of each generator to limit current flow at third- and higher-order harmonic frequencies. Reactors can be tuned to specific frequencies that are the biggest problems, but typically they are designed for 150/180 Hz, as this is the most problematic harmonic. The major issue in the use of reactors is their cost, and the custom nature of their design, making them problematic to acquire and install quickly. Also, the failure of the reactor may go undetected for a long time, resulting in a change in the effecting bonding arrangement of the system and potential unexpected hazards.

Compensate for the incompatibility by over-sizing the neutral conductor and derating the alternators.

7.4.3.2.4 Derating Factors for Alternators Exposed to Harmonic Neutral Current

In 4-wire generator installations that use dissimilar generators, generator neutral current should be measured to verify that operation of the generators in parallel will not result in system operation problems or premature generator failure. If there are no other related problems in the system, the designer may allow system operation with the neutral current and compensate by derating the alternator.

The derating factors can be calculated as follows:

Maximum allowable load on alternator (KVA) = $[I_R / \sqrt{(I_R^2 + I_N^2)}]\ (KVA_{gen})$

where:

I_R = output current of the generator set at full load and rated power factor

I_N = neutral current of the generator set at full balanced load, paralleled

KVA_{gen} = alternator rated KVA at maximum temperature rise

Note that the alternator itself generates some harmonic voltages, and load devices also can cause harmonic voltage distortion by drawing non-linear load current from the alternator.

As noted previously, load devices can also affect generator system voltage waveform quality. It is not uncommon to have very high levels of current distortion in load devices. The only way to compensate for this distortion is to provide relatively large alternators in the system, so that the system can duplicate the capabilities of a utility service. With modern facilities, system operational problems should not appear if the overall total harmonic distortion of the voltage waveform with loads running on the generator set is not more than 10–15%.

7.4.3.3 Load Sharing Control System Compatibility

Generator sets cannot operate in a stable fashion in parallel with other sources unless the loading on the generator set is controlled. When generator sets are operating together on an isolated bus (that is, not grid-paralleled), they are commonly provided with equipment to allow each machine to operate at the same percentage of load as the percentage of load on the total system. This is termed a “load sharing control system.”

Many options are available for load sharing controls from various manufacturers, and many of these options are not compatible with each other. So, when considering the paralleling of dissimilar generator sets, or adding generator sets to an existing paralleling system, it is critical to understand how load sharing can be accomplished.

Because having compatible load sharing controls is critical, consider replacing the control on the older generator with the same control that is on the new generator, if this is practical. When it is not practical to replace the old control it is often possible to put the new control "on top" of the old control. The new control will communicate with the controls on the new gensets to manage the load sharing function and will communicate with the "old" generator control over the voltage and speed bias lines. The old control still controls the genset, including the AVR and the governor, with the new control providing voltage and speed bias inputs so the generators will share the load correctly. Reference the attached figure for a block diagram illustrating this concept.

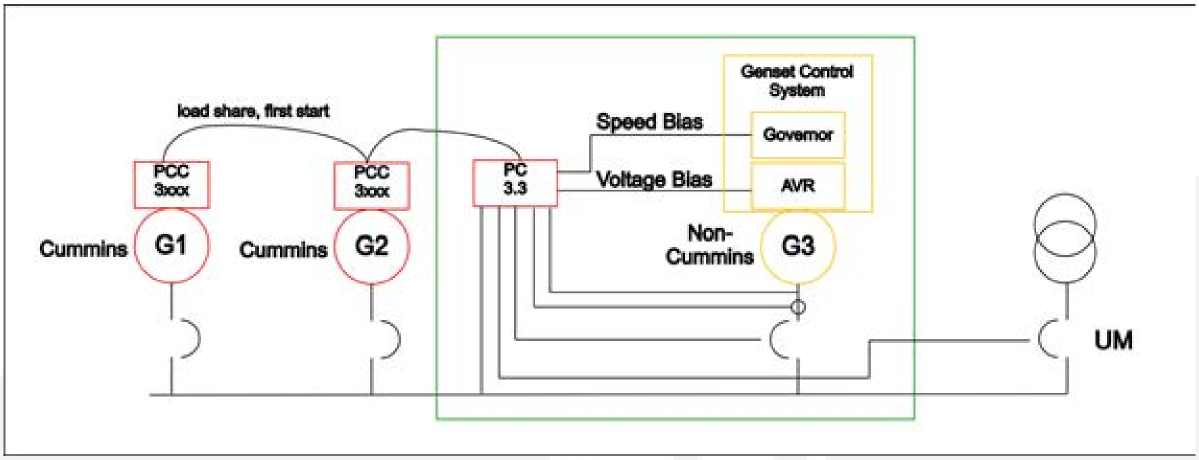


FIGURE 99. OLD AND NEW CONTROLS WORKING TOGETHER.

7.4.3.3.1 The Need for Load Sharing

When a generator set is in a paralleled arrangement, the voltage and frequency outputs of the generator sets are forced to exactly the same values when they are connected to the same bus. Consequently, generator set control systems cannot simply monitor bus voltage and speed as a reference for maintaining equal output levels, as they do when operated in isolation from one another. If, for example, one set operates at a higher excitation level than the other sets, the reactive load will not be shared equally.

Similarly, if a generator set is regulated to a different speed than the others, it will not share kW load properly with other generator sets in the system. Each generator set in the system has two active control systems always in operation: the excitation control system regulating voltage, and the fuel control system regulating engine speed. Generators can be sharing kW load and have problems sharing kVAR load, and vice versa. Successful load sharing requires addressing of both kW and kVAR load sharing, under both steady state and transient conditions.

Real power sharing (expressed as kW or unity power factor load) depends on fuel rate control between the generator sets based on percentage of kW load.

Reactive power (expressed as kVAR control) and excitation system control is dependent on the percentage of load between the generator sets. Although it is sometimes possible to integrate systems from different manufacturers, generator set governors and load sharing controls should be of the same manufacturer and model to avoid conflicts in responsibility for proper system operation. When that is not possible or practical, the detailed options of this section can be consulted for alternatives.

Several types of load sharing control are available:

- Droop governing and voltage regulation (a.k.a. “reactive droop compensation”)
- Cross current compensation for kVAR load sharing
- Isochronous kW load sharing
- Isochronous voltage kVAR load sharing

7.4.3.3.2 Droop Load Sharing

As illustrated in the figure below, droop governing or voltage regulation allows the engine speed (measured in Hz) or alternator voltage to decline by a predetermined percentage of the output range as the load increases. By contrast, if two machines start at the same frequency and voltage at no load, and maintain those values through all load levels (steady state), the system is said to be operating isochronously.

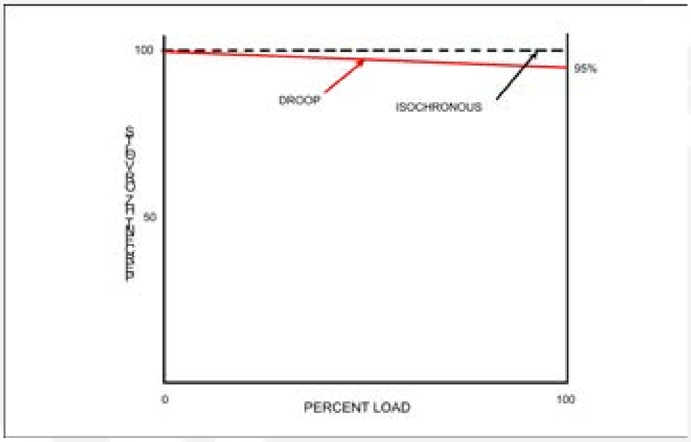


FIGURE 100. A DROOP CONTROL SYSTEM CAUSES THE FREQUENCY OR VOLTAGE TO DROP AS LOAD INCREASES.

For proper operation of a droop voltage regulation system each generator must be set to drop voltage at the same rate from no load to full load. For proper operation of a droop governing system each generator must be set to drop frequency at the same rate from no load to full load.

It is worth noting that frequency droop and voltage droop do not need to be the same percentage. Droop can be calculated as follows:

Frequency (Hz) droop: $(100)[(Hz_{NL}-Hz_{FL}) / Hz_{FL}]$

Voltage (V) droop: $(100)[(V_{NL}-V_{FL}) / V_{FL}]$

NL = no load

FL = full load

The figure below illustrates the impact of incorrect no load voltage settings. Generator 1 always carries more load than Generator 2. Generator 2 experiences reverse kVAR at no load.

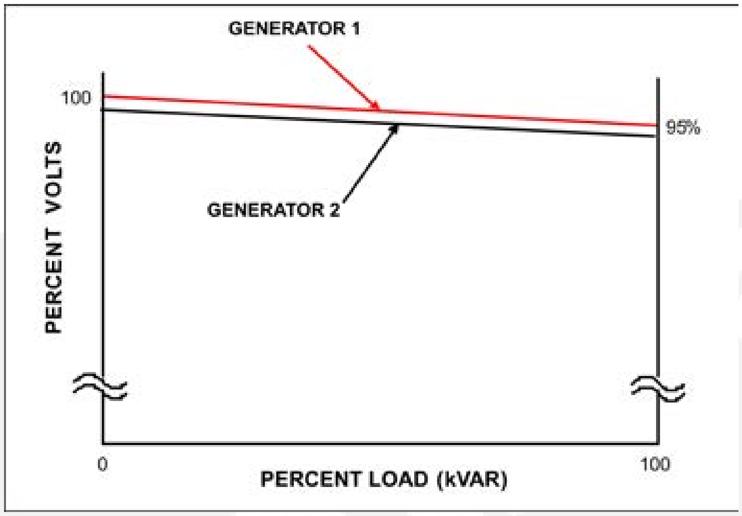


FIGURE 101. GENERATORS PARALLELED AT INCORRECT VOLTAGE BUT WITH PROPER (IDENTICAL) DROOP.

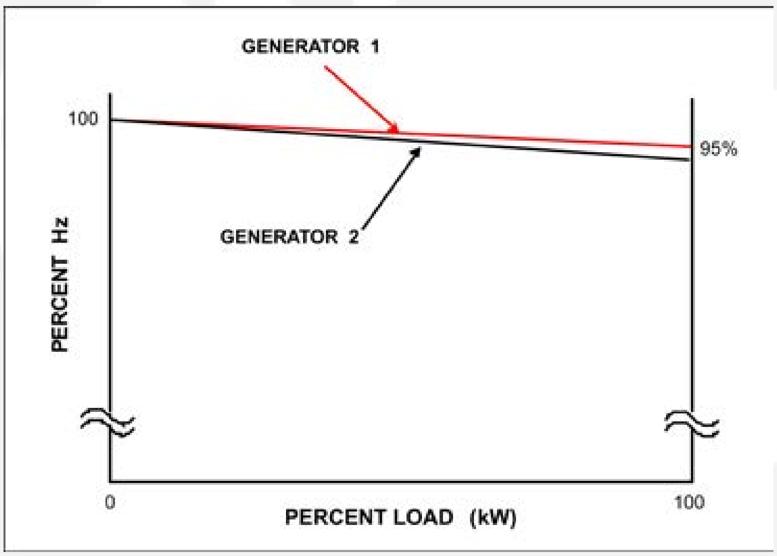


FIGURE 102. GENERATORS PARALLELED AT CORRECT NO LOAD VOLTAGE BUT WITH IMPROPER DROOP.

Note that systems always require both kW and kVAR load sharing, but they do not both need to be the same type of system. One can be isochronous and the other can be droop. VAR load sharing via droop is often termed “reactive droop compensation.”

The major advantage of using droop in paralleling is that it allows dissimilar machines with dissimilar voltage regulation or governing control systems to be paralleled without concern for their load sharing interface. The voltage variations that occur due to droop operation are not significant in isolated bus systems, but the frequency variations that occur due to droop operation can be significant, especially in emergency/standby systems where the load can vary considerably over time. Common droop selections for frequency and voltage can be different and are typically in the range of 3–5% from no load to full load.

Droop governing can generally be used for generator loading control in single generator set-to-utility paralleling systems, because the utility frequency is usually very constant. However, reactive droop is not effective for utility paralleling due to the greatly varying voltage level at any point in a utility distribution system as the load on the system changes. Var/power factor controllers should be used when generators are paralleled to a utility or other “infinite” source. If generators are paralleled to a utility with known frequency variation, a load governing system that is not frequency sensitive should be used.

7.4.3.3.3 Cross Current Compensation

Cross current is a flow of electrical current between generator sets that is caused by dissimilar excitation levels in those sets. Cross current compensation is a term describing the operation of paralleled generator sets without intentional voltage droop. This is achieved by the insertion of a current transformer (CT), usually on “B” phase of each generator, and interconnecting the CTs together to provide an identical voltage bias to each AVR in the system. The system works best when the voltage regulators are all of the same manufacturer and model. Not all voltage regulators work together in this mode, so the best planning practice is to make sure that all voltage regulators in a system that use cross current compensation are identical. This may require changing all the voltage regulators in the system to a new model. Using cross current compensation results in no intentional droop in voltage from no load to full load on the system, so it is considered to be superior to a reactive droop compensation system from a performance perspective. See **Figure 9**.

7.4.3.3.4 Isochronous kW and kVAR Load Sharing

Isochronous load sharing control systems are active control systems that actively calculate the percentage of real and reactive load on a specific generator set, compare those values to the percentage of real and reactive load on the system, and then provides control to the fuel and excitation system of the generator to drive the percentage of load on the generator to the same value as the percentage of load on the system.

Load sharing is critical to paralleling compatibility, because the load sharing communication is the only point where generator controls interact with each other when operating on an isolated bus. The figure below shows this interface.

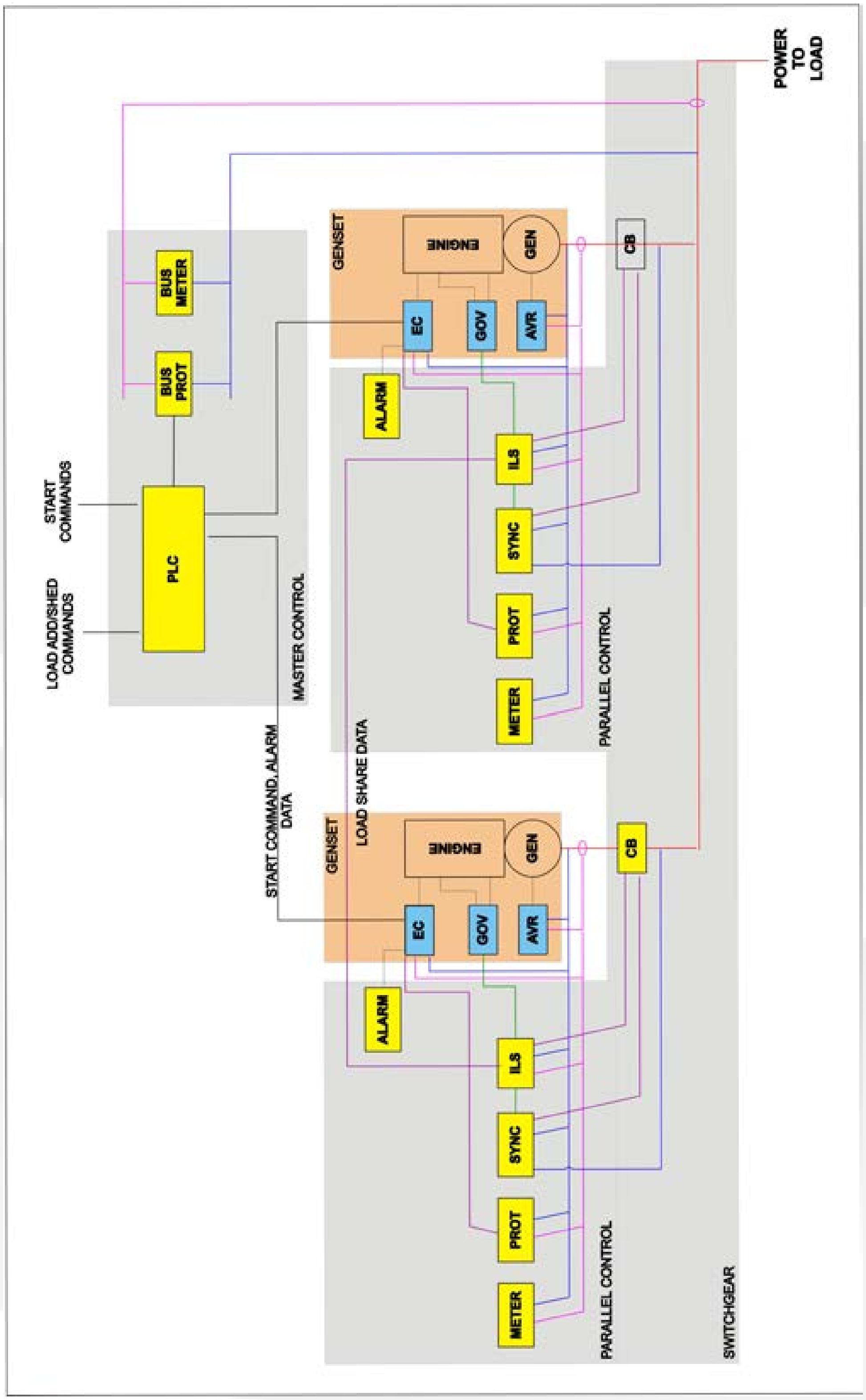


FIGURE 103. A BLOCK DIAGRAM SHOWING THE LOGICAL ARRANGEMENT OF CONTROL FUNCTIONS FOR AN ISOLATED BUS PARALLELING SYSTEM. NOTE THAT THE ONLY PLACE WHERE THE GENERATOR SET CONTROLS INTERFACE WITH EACH OTHER IS WITH THE LOAD SHARING INTERFACE.

To provide load sharing functions, each generator set in the system must have controls that will calculate the total percentage of kW and kVAR load on the machine, and then have a means to compare that value to that of the system as a whole. Several approaches are available in the marketplace to provide this interface. In general, they can be broken into two large groups: systems that use analog signals for load sharing, and systems that use digital communication signals for load sharing (such as CAN, RS485 or Ethernet). Analog control systems often respond faster than digital communication/control systems and can often be made to be compatible between different manufacturers.

Some manufacturers can provide an analog isochronous load sharing interface (ILSI) module that can be used for interfacing load sharing controls that use analog signals.

Digital communication/control systems are different for every supplier, so any system that uses them needs to have load sharing control functions done by the same make and model of equipment. The newest integrated paralleling controls (those that provide all the paralleling functions on a single circuit board) almost all use proprietary digital communication/control signals for load sharing. As a result, as a new supplier approaches an existing generator set with paralleling equipment in place, the typical recommendation will be to replace the existing paralleling controls with new controls all from the same supplier. This has been particularly common as the cost of these single board controllers has dropped dramatically compared with historical control systems for load sharing and other paralleling functions. While this may seem excessive or difficult (in the past it would have been), in fact it may be the most reasonable approach to managing the load sharing interface.

The latest digital controllers integrate all the paralleling functions into a single control board, which has a common load sharing interface (speed bias to governor control and voltage bias to the AVR), making the controls easy to interface with nearly any generator set.

At least one supplier offers a load sharing interface module (gateway) for use with digital communication control-based load sharing equipment, but a designer will need to clearly identify the responsibility for performance of the system if the gateway is not fully functional, or be prepared for more dramatic system changes if the load sharing gateway performance is not acceptable.

7.4.3.3.5 Using Different Operating Modes for Load Sharing

The availability of single board paralleling controllers for upgrade of existing equipment has led to a whole range of possible variations in how generator sets can be added to existing systems, and how paralleling control upgrades can be accomplished. When trying to interface dissimilar load sharing equipment from different suppliers, it is also possible to configure the system so that some of the generator sets in the system operate at a base load level, and others operate in a load share state. The base load machines operate at a constant load, while the generators operating in isochronous load sharing mode will “float” with the balance of the available load. Occasionally the total load on the base-load machines will be manipulated by a PLC. This system is viable when there are not sudden large load changes in a system.

The figure below illustrates a situation where three 1000 kW generators are connected together in a system, with one machine dissimilar to the other two.

In this case, since the system is an isolated bus arrangement, assume that the generators share reactive load via droop. The kW load sharing could be accomplished as follows.

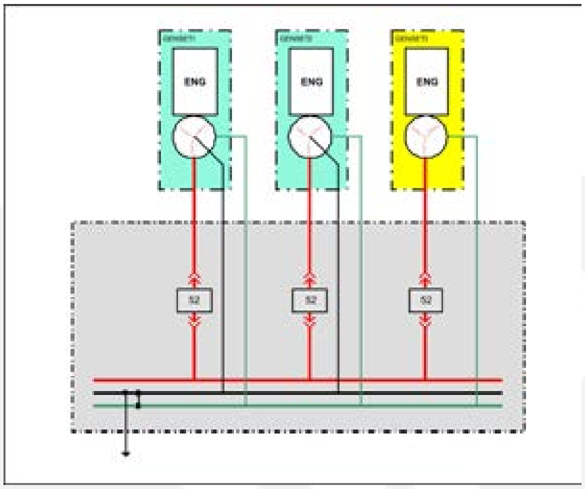


FIGURE 104. SYSTEM WITH TWO IDENTICAL GENERATOR SETS AND ONE DISSIMILAR, SHOWING NEUTRAL NOT CONNECTED ON DISSIMILAR MACHINE.

Generator 3 (yellow machine) is set up so that it cannot be the first to start, and it is not used unless at least one of the other generators is on the bus. It operates in droop for kW load sharing. With the other two machines operating at 60 Hz, Generator 3 is set to operate at a slightly lower speed at its full load that is sufficient to cause it to operate with a 500 kW load when in parallel with either or both of the other machines.

With Generator 1 and Generator 2 running and carrying system load, Generator 3 is synchronized and closed to the bus, and it assumes its preset load level. It operates at a fixed load until it is disconnected from the bus. In a similar fashion, load govern (grid-parallel) loading controls can sometimes be used to cause some of the machines in a system to operate at a fixed kW and/or kVAR load level, while the balance of the system operates isochronously and shares load proportionally.

In cases where this is used and the load level on the system varies significantly, a PLC or other device may be used to vary the load level on the machine (or machines) in load govern state to prevent over- or under-loading of the machines operating in load share mode.

7.4.3.4 Compatibility with Other Control Subsystems

Individual generator sets in a paralleling system may interface to each other and the balance of the facility in a number of ways, including:

- Generator sets must have a means to determine which generator set will close to the bus first in a “black start” (first start) situation.
- Generator sets often provide status information to a system master control, for the purpose of displaying data, allowing the master control to control system power capacity, and for central system load management.
- Generator set may be monitored by a facility monitoring system, or by an external monitoring system, such as for service contract facilitation.

In general, these communication tasks are handled by commonly available communication practices such as discrete signals or by digital communication such as RS485/Modbus[5] register maps. So the main concern in dealing with them is to simply plan for them carefully. Use of common paralleling controls for all generator sets greatly simplifies this work.

[5] Modbus is a trademark of Schneider Electric.

7.4.3.5 Picking the First Generator to Close to the Bus

First Start (or more properly, first to close) control is handled in different ways by different vendors. Some suppliers simply use a dead bus sensor for each generator set synchronizer, which allows each paralleling breaker to close to the bus if voltage is not sensed on the bus. This is a risky practice because it is quite possible that multiple generators can reach a decision to close to the bus at the same time, resulting in out-of-phase paralleling of the machines.

To prevent out-of-phase paralleling on energizing a dead bus, most systems provide a means to positively select the first generator set to close to the bus and prevent other machines from closing until the bus is energized and oncoming machines are properly synchronized. The devices and practices for providing this function are different between suppliers, and generally not compatible with one another. A system designer can deal with this by preventing dissimilar machines from closing to the bus until at least one other machine has closed. This is a viable alternative if there are multiple machines available with compatible First Start systems, so that it is likely that the bus will be energized without the “odd” machine coming on line. It is also possible that a PLC-based program can duplicate the logic of one of the suppliers to get this detail covered.

7.4.3.6 Alarm and Status Information

Alarm and status information on generator sets has traditionally been provided with discrete (contact based) signals that operate a relay and light a lamp if there is a specific alarm or status condition present. These signals are available on nearly any generator set and are compatible with most systems, so they do not represent serious issues, although there is a risk of incompatibility if planning is not carefully done.

Modern engines and the generator sets they are built with can have literally hundreds of alarm and status conditions, and the traditional conditions annunciated are not necessarily the most common or useful information to pass to the system operator. AC data and engine operating data are also useful in remote monitoring. Since most generator sets now are built with processor-based controls, most of this type of information is available via both digital communication mechanisms and traditional relay-based formats. The designer simply needs to decide what information is needed and specify what means are to be provided to pass the information to the user.

Options for remote monitoring include traditional alarm panels, alphanumeric displays, and touchscreen displays. Digital information is also easy to transfer into web-based monitoring systems and text-messaging systems.

7.5 Utility (Mains) Paralleling

Utility (mains) paralleling (the operation of one or more on-site generator sets in parallel with the utility service) is often used in applications to prevent power disturbances when transferring loads between live sources, or in the course of providing power to the grid for interruptible or cogeneration applications.

A utility paralleling system can be designed to export power either to the utility grid (utility distribution system) or to the facility only (i. e., generator set power is restricted to less than the facility demand). Although protective-relaying requirements vary with the application, the control equipment required for generator set operation would be similar in either case. This system could also provide complete automatic emergency backup because the operating mode would be similar to the standby/non-load break system described previously.

Local utility approval is always required before on-site generation equipment is paralleled with the utility service. The utility service supplier will want to review the specific application so that they can be sure that the customer owned equipment will not affect the quality of power delivered to other customers, and to maintain the safety and reliability of their system and equipment. It is possible that the addition of a generator set on a utility distribution grid will require improvements or changes in the utility system equipment, particularly when the generator equipment is exporting power on a regular basis to the grid.

7.5.1 Utility Paralleling Requirements

The utility requirements for facilities will vary between specific utilities, and even between facilities within a specific utility's service area. In general, however, the following items are normally required:

7.5.1.1 Power Quality

The utility service provider may want to review the harmonic characteristics of the generator set (or sets) that are paralleled to their system, to be certain that the generator sets do not induce damaging or disruptive harmonics into the system that may affect other customers' systems. A harmonic analysis of the generator output may be requested to document the generator set performance.

The utility may require use of an alternator that has 2/3 pitch to minimize the potential impact of 3rd order harmonics and their multiples. (For more information on alternator pitch, see Section 7.4.3.2 on page 218 in this section.)

7.5.1.2 Safety and Reliability

The first concern of the utility will be for the safety of their linemen working on a downed utility feeder. While utilities commonly utilize work rules that result in any line being treated as being live, it is common practice to disconnect and ground the portion of a line being serviced, in order to reduce the risks of working on the line

A parallel generator set bus may contribute significant short circuit current to a fault in the utility distribution system while the generators are connected to the utility. This fault current may result in total current levels that exceed the ratings of the equipment installed. Consequently, a review of the fault current contribution and the impact of that contribution may be required. See T-030 for details of fault current calculations for the generator set equipment.

It is also possible that if a generator system is paralleled to the grid, a fault on the grid may not be detected properly due to the contribution of the generator system while feeding the fault. An analysis of the protection system on the utility distribution grid is required to verify that this will not be a problem.

The system must incorporate anti-islanding provisions. (Islanding is the unintentional operation of a portion of a utility distribution system due to failure of a portion of the system, or isolation of the loads by a utility protective device.) Anti-island protection is typically provided by use of prescribed protective relaying and relay settings, but it may have functions that are logically controlled by the generator equipment.

The utility may require protective devices from a specific manufacturer. Typically, the customer will propose protective equipment for the application based on published utility requirements, and the utility will either approve or disapprove the design. As the use of paralleling load transfer equipment becomes more common, however, many utilities are providing standard interconnect requirements for their customers. The most common requirements for utility protection include phase sequence, high speed under frequency, and reverse power relays.

The utility may require a lockable visible disconnect, with 24–hour per day utility access. This allows the utility to disconnect the customer equipment if necessary for isolation of the utility system for service, or if operation of the customer–owned generation equipment disrupts other equipment in their system.

If the equipment provided is the service entrance for the facility, a UL (Underwriters Laboratories) service entrance listing and specific metering and CT (current transformer) compartment provisions may be required.

To prevent accidental out–of–phase paralleling of the on–site power generation equipment with the utility on recloser operation, interlocks with utility–owned reclosing equipment may be required.

The protective relaying provided for paralleling load transfer equipment may be either industrial grade or utility grade equipment. In general, industrial grade equipment is considered to be less reliable and precise than utility grade equipment, but is much less expensive.

Utility grade protective relaying may be either electromechanical or solid–state /microprocessor–based equipment. Suppliers generally provide equipment as specified, but recommend solid–state protective relaying for most applications because it offers more flexibility and requires less maintenance than electromechanical equipment. Often microprocessor-based relays have multiple functions, reducing the overall cost and improving the reliability of system protection.

The typical practice for low voltage applications is to provide industrial grade equipment for generator protection and utility grade equipment for utility protection. For medium voltage applications, due to the higher replacement cost of many of the components in the system, utility grade protective relaying may be specified for both the generator set and utility protective functions.

The customer should obtain written approval of the intended installation design from the utility prior to energizing the equipment.

Special care should be taken when generator sets are expected to synchronize to a utility service that is fed from a network protector system. A network protector is an automatic control and power transfer device which provides power to a load circuit from multiple utility services. The control system in the network protector monitors the sources feeding it, and automatically serves the load with the best source available. In order to provide this service to the loads, the network protector incorporates sensitive protective relaying that can be disrupted by a generator set that is paralleling on the load side of the network protector.

Regardless of the system design, a well-defined sequence of operation must be established before the equipment is designed. Questions to be addressed before the design sequence is written are:

- Can the facility export power to the grid?
- Can the facility stay paralleled indefinitely, or for short periods only (i. e. closed transition transfers)?
- What is the desired operation in the event of a fault?

7.5.1.3 Utility Protection

Protection needs vary by application, but in general, Cummins supports use of the IEEE1547 requirements for interconnect protection of synchronous generator equipment. The requirements include under/over voltage (27/59), under and over frequency (81 o/u), anti-islanding protection, and compliance to synchronizing accuracy requirements. Unique site requirements may require other protective devices or protection provisions.

7.5.1.4 Generator Set Protection When Utility Paralleling

Generator sets used in utility paralleling applications are similar in design to those used in other paralleling applications. However, the cross-current and load sharing equipment used on nonutility paralleled equipment will not function correctly in parallel with an infinite bus, because the generator set (or sets) cannot control the bus voltage or frequency. In addition to the standard generator set paralleling equipment (refer to **Chapter 3 on page 17**), the following components are required:

VAR/PF controller - to control generator reactive load level. The VAR/PF control system should include a voltage matching capability, so that disruptive transient currents are not induced on closing a non-matched generator voltage to the facility distribution system.

KW loading control - an active import/export control, working with an isochronous governor system - or a simple droop governor module for the system.

Droop governing is a considerably less expensive alternative than active load control and is an appropriate choice when the system is intended to export power at a fixed kW level. If load ramping in conjunction with a non-load break system is desired, droop governing should not be used for utility paralleling.

Remember that droop governing works well only with a stable utility source, because frequency changes will result in significant load changes.

Whichever governing system is used, remember that utility paralleling requires controlled kVar load sharing with the utility. The voltage changes that are common with any service will result in significant load swings in the systems.

It is also worth noting that if dissimilar generator sets are installed in a facility, but are not paralleled together on an isolated bus, they will not have control compatibility issues, because the load sharing controls are not operational when paralleled to the utility.

7.5.1.5 Other Interface Requirements

As should be apparent after review of this material, a planned approach is needed whenever a system is intended to parallel with the utility grid. Early and thorough communication with the utility/mains service supplier is necessary to achieve a successful, on time installation.

Once installed, it is necessary to test and calibrate system equipment. This may require the services of 3rd party testing agency.

The IEEE 1547 series of standards includes detailed information on the design and application of distributed generation equipment in parallel with the utility service.

8 Appendix

8.1 System Documentation

Proper documentation is essential to the installation, support and operation of any on-site power system.

Because of the complexity and custom nature of most paralleling systems, custom-written manuals should be provided for each project.

These manuals should include installation instructions, operating instructions, maintenance recommendations, and service and troubleshooting procedures for all system components. They should also include detailed interconnection information for all components that interface with the generator sets, paralleling equipment, and transfer switches.

System documentation must be detailed and complete. Each component in the system is documented as a single item, with performance and design information included in the drawing document. This information is required whenever substitutions of components are performed .

System control and outline drawings are permanently recorded and logged at the factory.

Paralleling system control drawings typically include:

- System one line AC drawings; 4 wire, showing all AC interconnections
- DC drawings; ladder drawings showing control logic
- Wiring Diagrams; showing point-to-point wiring details and physical locations of components.
- Material lists; provide a common key to all drawings in the system and a single point for information on settings of breaker trip units and relay settings.
- Microprocessor DC Logic Diagrams (when used); allow analysis of system operation sequence.
- Interconnection drawings showing the wiring interface between all components in the system.

8.2 Test Recommendations

Paralleling systems are relatively complex. To achieve easy installation, smooth system commissioning, and trouble-free operation; complete, comprehensive system testing is necessary.

Typically the testing sequence for emergency power system equipment is composed of three separate types of testing:

- **Prototype testing** of components and major assemblies.
- **Factory testing** of the complete system and its major individual assemblies.
- **On-site testing** of the entire installed power system, complete with all interfacing accessories.

Each of these test sequences is important because together they verify the reliability of the installed system.

8.2.1 Prototype Testing

The primary function of prototype testing is to prove the reliability of the product design, through extensive, and often destructive, testing processes.

Generator set prototype tests typically include endurance testing, short circuit testing, and temperature rise testing (among other tests).

Switchgear prototype tests typically include short circuit testing, temperature rise testing, and insulation resistance testing.

The short circuit testing verifies the integrity of the bus design. The temperature rise testing checks that operation of the equipment will not result in excess temperature levels in the equipment.

In addition, all system components are tested through a similar cycle by the manufacturers.

8.2.1.1 On Site Testing

The primary function of on-site testing is to verify that the equipment has been correctly installed. (Factory testing should have already verified that the equipment performs to specification requirements.)

In addition to the testing normally required to verify that the generator set has been properly installed (see NFPA 110 for typical test procedures), the on-site testing of the paralleling system should include a complete duplication of the functional testing that was done at the factory.

On completion of the installation and functional testing, it is important to perform a complete system power failure test (opening facility mains to simulate power failure), to verify that all operating systems perform as expected. Throughout this testing, all system instruments should be carefully monitored to verify that the system is operating in a stable, predictable fashion.

8.2.2 Factory Testing

The primary function of factory (production) testing is to verify that the production equipment will perform to the same standards as the prototype equipment.

Just as it would not be considered acceptable for a supplier to ship a separate engine, generator, and control to a job site without being assembled and tested at the factory, it is unreasonable to expect optimum paralleling system performance without complete factory testing.

Obviously, destructive testing is not appropriate. The primary effort is directed toward functionally testing all facets of the system's performance.

Factory tests allow custom paralleling switchboards and master controls to be completely interconnected with the generator sets to verify that all interconnection points and functions perform correctly. Cummins testing process typically utilizes generator set simulators connected to actual generator set controls to allow the entire system to function as if it were connected to operational generator sets without the time constraints and costs associated with switchgear tested in test cells with fully operational generator sets.

The load sharing controls can be calibrated under controlled conditions, at rated load and power factor, with load banks. This would be difficult or expensive to accomplish on a typical job site.

Because all the system loading is completely isolated from operational equipment, and complete flexibility in the test procedure is available; the factory test provides an ideal time for the customer to review operation of the system.

The factory test of a paralleling system should include the following tests:

- cold start test
- manual paralleling tests
- automatic paralleling tests
- complete functional operation tests
- steady state and transient load sharing tests

8.3 Start Up and Commissioning

Generator set, ATS and the standard Digital Master Controllers start up and commissioning instructions are provided within Cummins Power Generation installation and service manuals.

It should be noted that in some applications with custom built Digital Master Controllers, these require factory assistance to start and commission.

An example of standard product start up and commission information is as follows:

8.3.1 Generator Sets

8.3.1.1 General

This section describes a process which can be used in the initial startup and test of generator sets which are paralleled using typical PowerCommand Digital Paralleling controls. PowerCommand Digital Paralleling systems have many functions which are common to traditional paralleling systems, but they are completely different in the way that these functions are supplied in the system. The intent of this section is to provide you with guidance in the initial set up, operation, and testing of the equipment, so that you can perform this function with as safe and efficient procedures as possible.

DANGER: High voltage.

The PowerCommand Control cabinet contains high voltages when the generator set is running. It can be energized from the system bus and contain high voltages even when the generator set is not running. Contacting these high voltage components will cause severe personal injury or death.

Do not attempt to service, operate or adjust the control unless you have been trained in proper service techniques.

This procedure assumes that the technician performing the commissioning process is fully familiar with the PowerCommand 3201 control. This procedure must only be performed by technicians trained in proper operation and service of the 3201 controller.

8.3.1.2 Startup Process

The startup process described in this section is typical for paralleling systems which utilize PowerCommand Digital Paralleling equipment. Every paralleling system is different in its design and application, so portions of the recommended procedures may be inappropriate for your application, or some procedures may be needed which are not described in this section. If at any time you are unsure of the proper procedure or practice for a specific situation, consult the factory or other qualified technical sources for assistance. Serious damage can occur to equipment due to misoperation of equipment or incorrect commissioning practice.

In general, the startup process contains these major steps:

- Installation design review, including mechanical and electrical support systems for the generator sets and paralleling equipment
- Individual generator set preparation, operation, and performance review
- Manual system operation
- Automatic system operation and adjustments
- Black start testing of system
- Customer acceptance testing
- Customer training
- Issuing an installation report showing the work done, system performance, and customer acceptance

8.3.1.3 Equipment Application Review

The purpose of the equipment application review is to inspect the installation to confirm that the equipment has been installed within parameters specified in the installation manual for the equipment, Cummins application manuals, and applicable codes and standards. The equipment should not be started unless the installation is properly completed. Cummins technical application manual *T-030 Liquid-Cooled Generator Sets* provides guidance in evaluating generator set installation requirements. It is recommended that an installation review report form be used to avoid missing any major points in the equipment review and simplify reporting of problem areas to the installer or customer. T-030 includes installation review forms for use in this activity.;

Using the system wiring and interconnection drawings, verify that all interconnecting wiring is properly connected and the terminations are tight.

In addition to the generator set installation, it is critical that the installation of the switchgear is properly accomplished. Three critical installation parameters, at a minimum, must be verified:

- Each power and control termination must be properly tightened.
- There must be an equipment grounding conductor (earthing conductor) connecting each grounding point of each device in the system to each other and to earth ground.
- For low voltage systems, there should be a neutral to ground bonding connection on each neutral bus, but ONLY ONE. See section 7.3 for potential arrangements that are acceptable. Note that when 3-pole transfer switches or breaker transfer pairs are used, the neutral to ground bonding connection is at the utility service entrance, and a second connection at the generator set, even it is a great distance away is not acceptable.
- For 3-wire systems, the neutral of the generator set is usually bonded to earth/ground, and no neutral is connected at the bus PT.

The system startup process should not proceed until the inspection and review are complete and all issues resolved.

8.3.1.4 Individual Generator Set Startup

The generator set should be properly serviced, with proper levels of coolant and lubricants in the system. Care should be taken to remove all shipping blocks and braces from the equipment. Complete all pre-start service and checks as for a standard non-paralleled generator set. See generator set installation manual for further required work.

Equipment needed to perform the startup:

- Two properly calibrated hand-held digital meters. Be certain that the meters are rated for use on a circuit operating at the rated voltage of the generator set.
- Phase rotation meter.
- Any control or equipment tools that are necessary for set up and calibration of the generator sets, controls, breakers, or other system devices. For Cummins systems, most control set up and calibration can be done with Cummins InPower™ software.
- Individual generator set and system drawings, specific to the project being installed.

A two channel strip chart recorder with voltage and frequency modules is helpful, but not required for the startup. InPower may be used for this function with Cummins equipment.

Operate the generator set OFF/MANUAL/AUTO switch to the OFF position. Connect the generator set starting and control batteries at their proper locations and verify that no fuses are blown (indicating improper connections in the system). Verify that the stationary battery chargers are properly installed and wired and turn them on.

If the system includes a master control panel, verify that control power is present in the master control and operate the system mode select switch to the manual operation position, so that the system does not inadvertently issue or receive a start signal. Mark the system to note that it should not be moved to the auto mode or started. If the system includes a touchscreen, PLC bridge/MUX or network interconnections, verify that these are all functional.

For Cummins generator sets, connect InPower to the generator set controller, and make a capture file of the initial control configuration and settings. Save the file with the project name, date, and a notation that it is the initial configuration.

Configure the generator set so that it will start and run initially at idle speed. If the generator control allows for it, disable the alternator excitation system.

Verify that starting the generator set and energizing the system bus will not cause hazards to other persons working in the vicinity of the equipment, or directly on the equipment or anything electrically connected to the equipment. Notify responsible persons in the building that the equipment may be energized and operating at any time.

Start the generator set by operating the mode switch to the MANUAL mode and press the RUN pushbutton to start the generator set. The generator set should start and accelerate to idle speed. An idle mode alarm should appear on the generator set digital display panel. Allow the generator set to run at idle, taking care to note unusual noises or vibration from the engine or alternator, leaking fluids or exhaust connections. Run the generator set at idle until the coolant temperature reaches normal operating temperature. Make any corrections necessary prior to continuing with the startup process.

With the generator set shut down, return the generator set to normal operation state by enabling the excitation system and operation at normal speed. Start and allow the generator set to run at rated frequency and voltage. Calibrate and adjust all generator set metering using the hand-held digital meter and the procedure described in the generator set control operation and service manual. Adjust the generator set to proper voltage and frequency. Record the values of voltage and frequency so that all units can be adjusted to the same values, using the same calibrated AC meter. Remember to save all changes and adjustments prior to switching off the generator set.

Set all protective functions in the generator set control based on the requirements of the application or as directed by the project consulting engineer; or, see “AC Protection Settings and Rationale” in the appendix for guidance. Set the protective devices for the paralleling breakers as is indicated by a coordination/discrimination study. Set distribution system devices as indicated in the same study.

Make sure that the paralleling breaker is charged and ready to close (power circuit breakers only) and that the paralleling bus is de-energized. If the breaker is not charged, manually charge the breaker. Manually close the paralleling breaker for the generator set using the manual close provisions in the generator set paralleling control. Most paralleling breakers will automatically re-charge on closing (power circuit breakers only). When the charging cycle is complete, electrically open the breaker using the breaker open control switch on the front of the PowerCommand control. Close the breaker using the breaker close switch on the alpha-numeric display of the PowerCommand control.

DANGER: Phase relationship testing.

Use extreme caution when performing phase relationship testing. The system is energized and dangerous voltages are present in many locations. Contact with energized parts will cause serious injury or death.

Do not attempt these tests unless you have proper equipment for testing and are trained in its safe use

.

Verify that the phase rotation of the generator set matches the phase rotation of the utility service at each transfer switch or breaker power transfer pair. Correct generator set phase rotation to match utility condition, if required, by reversing the phase L1 (A or U) and L2 (C or W) connections on the generator set output.

NOTE: The purpose of this procedure is to make sure that the generator set output matches the bus phase relationship. Later in the startup process the wiring and interconnection of the bus and generator set PT modules will be verified. Note that the PT/CT module phases must be matched to the generator set phase changes and the bus PT, or a FAIL TO SYNCHRONIZE alarm will occur.

With the breaker closed and the generator set operating at rated voltage and frequency, verify that the bus voltage displayed by the generator set is correct. If a master control is used in the system, make sure that the main bus metering is functioning and properly calibrated.

Using the load bank or available load on the system, check the generator set load carrying ability and the transient performance of the generator set. Adjust as necessary for proper generator set operation. Disconnect the load from the system.

Make sure that all alarm and shutdown circuits in the generator set are functioning properly. Shut down the generator set by switching the mode select switch to OFF.

Repeat the process described in this section for each generator set in the system before moving on to the next step of the startup process.

8.3.1.5 Manual System Operation

Once all generator sets in the system have been successfully run individually, the generator sets are ready for verification of manual paralleling capability.

Make sure that all generator set mode select switches are placed in the OFF position and that the AUTO/MANUAL switch in the master control (if used) is also in the manual mode position.

Operate the control switch of one generator set to the MANUAL position, push the RUN pushbutton, and allow the generator set to start and accelerate to rated speed and voltage. Manually close the paralleling breaker on this generator set by pushing the breaker close pushbutton on the front face of the PowerCommand control. Allow the generator set to run at no load for the first phase of the manual paralleling test.

DANGER: Use extreme caution when performing phase relationship testing. The system is energized and dangerous voltages are present in many locations. Contact with energized parts will cause serious injury or death. Do not attempt these tests unless you have proper equipment for testing and are trained in its safe use.

Check the phase relationship of the generator set output to its Bus PT module. The voltage difference between the L1 phase on the input to the Bus PT board and the generator set PT/CT board should be zero. Repeat this process for each generator set in the system.

Make sure that all generator set OFF/MANUAL/AUTO control switches are placed in the OFF position and that the master control AUTO/MANUAL switch (if used) is also in the manual mode position.

Start one generator set in the MANUAL/RUN mode and allow the generator set to start and accelerate to rated speed and voltage. Manually close the paralleling breaker on this generator set by pushing the breaker close pushbutton on the front face of the PowerCommand control. Check the phase relationship of the generator set which is closed to the bus, with each individual generator set. This can be accomplished by starting the second generator set in the system by operating the OFF/MANUAL/AUTO control switch to the RUN position and allow the generator set to start and accelerate to rated speed and voltage. When generator set frequency and voltage have stabilized, operate the display screen of the PowerCommand control to the voltage and frequency screens and use the digital display to verify that the generator set voltage and frequency matches the bus voltage and frequency. Check to verify that the synchronizer is enabled.

Switch the display screen to the digital synchroscope (bus frequency) screen and observe the control phase relationship between the generator set and the bus. When the phase relationship of the oncoming generator set is within the acceptance parameters programmed into the control, a SYNCHRONIZED message will be displayed on the screen next to the phase difference display.

When the asterisk is displayed on the control panel, check the phase relationship between the generator set and the bus. With the hand-held digital voltmeter, check the voltage from the line side to the load side for each phase of the open paralleling breaker on two phases simultaneously (Figure 8-1). If the phase relationship is proper, the voltage across the breaker (with the breaker open) should be zero, or nearly zero on both phases when the ”synchronized” indicator lamp is on. The voltage of the two meters should rise and fall at the same time.

NOTE: If the generator set output phase rotation matches the bus and a PHASE ROTATION warning appears when you attempt to close the paralleling breaker, you should check the generator set and Bus PT boards for proper wiring and interconnection. Both the primary and secondary wiring in the Bus PT board should be checked.

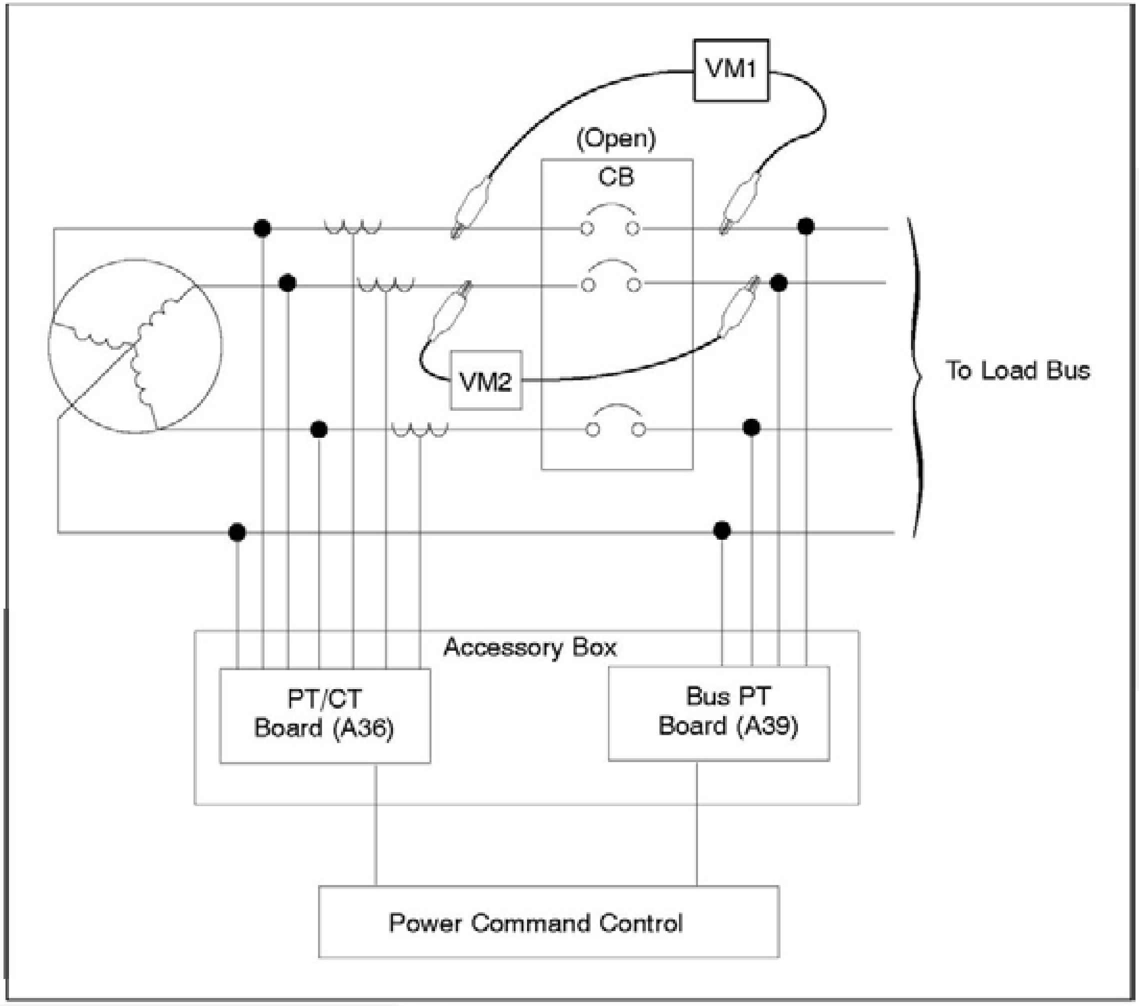


FIGURE 105. CHECKING PHASE RELATIONSHIP BETWEEN GENERATOR SET AND SYSTEM BUS ON A LOW VOLTAGE SYSTEM.

NOTE: For applications where a wye connected generator set is paralleled to a delta connected bus, the generator neutral bus must be floating and the neutral connection to the bus PT module must not be used.

Make sure that the “charged” flag is present on the paralleling breaker and push the breaker close pushbutton on the PowerCommand Control to manually close the oncoming set paralleling breaker and paralleling the generator set to the system bus.

NOTE: The breaker close function operates through a permissive relay function in the PowerCommand Control, so the paralleling breaker will not close unless the generator set is properly synchronized with the system bus.

Perform the phase rotation verification on each generator set in the system, prior to attempting to close it to the live parallel bus for the first time.

When all generator sets have been closed to the bus, observe the voltage, frequency, amp load and kilowatt load on each generator set metering set. The metering should indicate identical voltage and frequency readings on all generator sets in the system. Amp and kilowatt readings should all be zero. With no load on the system, a positive amp load reading on generator sets indicates a voltage difference between the generator sets in the system. A positive kilowatt reading on any generator set indicates a frequency misadjustment on at least one generator set. Perform adjustments necessary to eliminate circulating currents and kilowatt loads. Save the generator set adjustments made prior to switching off the generator set.

With all generator sets running in parallel in manual (RUN) mode, apply available load to the system. Observe load sharing levels on the generator sets. The units should share load proportionally. (The %load and %amps meters on the PowerCommand control should all read within plus or minus 5% of each other.)

Adjust load sharing parameters within control system to achieve proper load sharing. Save all changes.

If possible, operate the system at various load levels and verify proper operation at each level.

Remove all load from the system and return the generator sets to their normal automatic mode by placing the OFF/MANUAL/AUTO switch in the AUTO position.

8.3.1.6 Automatic System Operation

If the system includes a master control panel, move the mode selection switch on that panel to the full automatic position. Operate the test switch to cause the system to automatically start and parallel all generator sets. Alternately, a test switch from an automatic transfer switch may be used.

The generator sets should automatically start, accelerate to rated speed and voltage, synchronize and parallel on the system bus. As the generator sets synchronize and close to the system bus, observe the operation of the load adding (priority) control relays in the master control. (If load add control relays are provided.) Observe and record the time to synchronize for each generator set.

With all the generator sets running and closed to the system bus, apply load to the running generator sets, but at a low enough level that all the generator sets need not be running in order to carry the bus load. On one generator set, apply a jumper to the Load Demand input in the control box (TB3-38,39). The following sequence should then occur:

- The "LOAD DEMAND" shutdown message should be displayed on the PowerCommand digital display panel.
- The load should ramp down on the generator set to its minimum set point level.
- The generator set paralleling breaker should open.
- The generator should run for its normal cooldown period and then shut down.

When the unit has shut down, remove the jumper on the Load Demand termination point. The generator set should start, build up to rated frequency and voltage, synchronize and parallel to the system bus. When it has closed to the bus, it should ramp up to its proportional share of the total bus load.

Repeat the load demand test for each of the generator sets in the system.

Switch off the test switch in the master control or transfer switch. All the paralleling breakers should simultaneously open and the generator sets should run for a cool-down period and shut down.

Simulate a remote start in the master control. The generator sets should automatically start, accelerate to rated speed and voltage, synchronize and parallel on the system bus. Remove the remote start jumper on the master control. The generator set paralleling breakers should all open and the generator sets should run for a cooldown period and shut down.

At this point the various control functions of the master control can be tested and verified. Consult the project drawings and specifications or approved submittal documents for details on master control functions and requirements.

8.3.1.7 Black Start Testing

The black start testing process is designed to demonstrate that the entire on-site power system is installed correctly and that system support equipment, such as day tanks, fuel pumps, or supplemental ventilation equipment, is designed and installed correctly. It is primarily used in applications where the paralleling system is intended to provide emergency power in the event of a normal utility (mains) power failure. The black start testing process is performed after the entire on-site power system is installed. This testing process is often performed in conjunction with the customer approval testing, since it may be disruptive to the operation of the facility and demand special arrangements to avoid potentially dangerous or costly power failures in the facility.

The specific details of this testing process are very dependent on the design of the electrical and mechanical systems of the facility. In general the steps in this process are as follows:

- A power failure is simulated in the facility by opening the main power feeder in the building. It is desirable to do this to be certain that critical loads such as fuel pumps are fed from both the generator and utility (mains) bus.
- The generator sets start and parallel. The time required for the generator sets to start and parallel should be recorded and noted on the final test report for the system.
- Observe operation of all power transfer devices, noting the time required to transfer.
- The generator sets should be run in parallel with all available load in the building, at a minimum of approximately 30% of their standby KW rating. The duration of the test should be sufficient for the generator sets to reach their normal operating temperatures. The load demand system (if provided in the system master control) should be shut down until all generator sets in the system have reached normal operation temperatures and their operation temperatures have stabilized. During this process, data should be gathered to demonstrate the load applied and the operational performance of the system. It is customary to document the generator set performance during this period, by recording all values on all meters and engine monitors every 15 minutes.
- When all required customer testing and verifications have been performed, return the system to normal power by restoring utility (mains) power at the point where it was disconnected.
- Verify that the generator sets and power transfer devices all return to their normal ready-tostart states.

8.3.1.8 Test Reports and Acceptance

The technician performing the system startup should issue a start up and test report to document the work performed and demonstrate that the system is functional and operational. The exact requirements of this report will vary depending on customer requirements, but should include, as a minimum:

- The application and review and evaluation. A copy of the site review checklist performed at the start of the testing process might be included to document this step of the process.
- A copy of the startup check list (a typical check list is included at the end of this section), documenting the functions tested and that each function performed properly.
- Test data sheets documenting results of testing. A sample test format is included at the end of this section.
- List of all the settings of each generator set control.
- Black start test results.
- Certification that the system is operational and ready to run.

It is customary for an owner's representative to review and sign all test documents, indicating acceptance of the test data and system performance.

8.3.2 Switchboard and Switchgear

8.3.2.1 DOs and DON'Ts of Energizing a Switchboard

CAUTION: It is important to adhere to local codes of practice or local regulations governing electrical installation that may override instructions provide in this manual.

CAUTION: Installation, operation, and maintenance must only be done by persons trained with all respect of applicable safety practices and qualified to work on such devices. Personnel must also be aware of all the risks associated with working on live equipment.

DOs:

- The number one "do" for the switchboard is to use your common sense in knowing what is alive and how one function will affect another, for example, by removing a cover labeled 'DANGER LIVE BUSBAR' you will expose yourself to a live part.
- Take care with all panels and doors that have been removed off the board. Always look for a straight clean surface to lay the panel down. (Never stack panels on top of each other, this will cause denting and scratches.)
- Do inform everybody down the line if you are going to energize a new circuit.

DON'Ts:

- Do not remove covers and back panels without knowing which circuit has been energized, always review the state of what circuit is 'on' or 'off.'
- Do not operate any circuit without informing the people downstream when you will be energizing the circuit.

8.3.2.2 Suggested Start Up Procedure

Before starting or energizing the Main Switchboard, the following procedures must have already occurred:

- Megger Test
- All covers returned and fixed in their true position.
- Checking of all functional units and protective devices are set correctly.
- Cable Torque Checks have been completed on all cable lug bolts.

Before starting or energizing any subcircuits, the following procedures must have already occurred:

- Phase rotation checked.
- Correct termination of feeder cables to the generator sets.
- Personnel notified that the machinery will be operating and will be alive.

Before energizing the switchboard/switchgear the following procedures must have already occurred:

Generally the mode for energizing the board is to load the circuits stage by stage:

- The state of all ACB.
- Main contacts off.
- Turn on main switch.
- Turn on all required Feeder ACBs starting with largest current rating.
- Proceeding down the remaining ACBs.
- Check the voltage.
- The Switchboard should now be supplying each circuit as it is required down the line.

8.3.2.3 Suggested Shutdown Procedure

De-Energize the Switchboard/Switchgear

Generally the mode for de-energizing the board is to unload the circuits stage by stage. This has the advantage of being ready for re-energizing, as all the circuits have been already isolated.

- Turn 'OFF' the lowest current-rated MCCB and then proceed up to the largest current-rated MCCB
- All subcircuits have now been isolated.
- Turn 'OFF' main switch.
- Check that no voltage appears on load side of main switch.
- The Switchboard should now be fully isolated.
- To isolate the line side of the incoming MCCB, you must isolate the ACB feeder on 'A1' main switch board.

8.3.2.4 Frequency of Preventive Maintenance

The frequency of preventive maintenance for paralleling switchgear depends largely on the operating conditions. If the paralleling switchgear is operated under normal environment conditions, then the preventive maintenance frequency shall be according to the recommendations below.

TABLE 16. RECOMMENDED FREQUENCY OF PREVENTIVE MAINTENANCE

Inspection Type	Action or Work to be Carried Out	Frequency
Daily checks	View all indicating lamps and switches and verify that they indicate conditions are normal in the equipment	Daily
Daily checks	Visual Checks Listening for any abnormal indications such as excessive noise from within the switchboard	Daily
Yearly general inspection	Visual checks and general cleaning Visual checks of all bus bars for evidence of arcing or tracking. Re-torque all bus bar bolts to their recommended torque values. Functional units and protective device testing	Once a year
Maintenance of functional units and devices	According to respective user manuals For ACBs, please refer to recommended maintenance from Schneider Electric	

If the paralleling switchgear is operated in a clean environment, then the frequency of preventive maintenance can be reduced. Conversely, if the paralleling switchgear is operated in an environment which is exposed to dust, high humidity, corrosive vapors, and heat, the frequency of preventive maintenance needs to be increased.

8.3.2.5 Typical Preventive Maintenance Checklist

DANGER: Hazadous voltage.

The Paralleling Switchgear utilizes hazardous voltage, which presents a serious burn and shock hazard that can result in injury or death.

Observe all danger, warning, and caution notations within this manual and obey all safety placards on the equipment.

DANGER: Do not work on energized equipment. Unauthorized personnel must not be permitted near energized equipment. Due to the nature of high voltage electrical equipment, induced voltage remains even after the equipment is disconnected from the power source. During installation and maintenance operations, the equipment must be de-energized so as not to expose personnel to electric shock hazards. Plan time for maintenance with authorized personnel so that the equipment can be de-energized and safely grounded.

CAUTION: Installation, operation, and maintenance must only be done by persons trained with all respect of applicable safety practices and qualified to work on such devices. Personnel must also be aware of all the risks associated with working on live equipment.

TABLE 17. TYPICAL PREVENTIVE MAINTENANCE CHECKLIST

Action	OK	Defective/ Require Follow-Up Action	N/A
De-energize the power system and disable operational capability of generator set:			
a) Ensure the generator set and/or all electrical source to the switchboard is OFF.			
b) Disconnect the battery charger prior to removing the negative battery cable from the battery in order to prevent arcing. Disconnect battery cables with the negative (-) cable first.			
c) Ensure that all generator set circuit breakers (circuit breakers that feed power to the system) are OPEN.			
Cleaning of Paralleling Switchgear:			
a) Check the lack of humidity and foreign bodies inside and outside the switchgear.			
b) Thoroughly dust and vacuum all controls, meters, circuit breakers, and bus bar compartments.			
c) Check the outer finish of the switchgear. Touch up any paint scratches and replaced damaged parts if necessary.			
Visual Inspection:			
a) Visually inspect bus bars for carbon tracking, cracks, corrosion, change of color (hot points), or any other types of deterioration.			
b) Visually check the condition and tightness of the bus bar support.			
c) Visually check all control wiring and power cables for signs of wear and/or deterioration.			
d) Visually check all control wiring and power cables for loose connections. Tighten if necessary.			
e) Visually check system cabinets for loose or missing hardware.			
Preventive Maintenance:			
a) Tighten all system bus bar and cabinet hardware and all control wiring and power cables.			
b) Service or replace station batteries.			
c) Verify the proper operation of the station batteries and battery charger.			
Operational check:			
a) Energize the power system and enable the operational capability of the generator set.			
b) Run the System Test, if available, and operate all operational controls while observing meters and indicator lights.			
c) Check the operational capability of all protective circuits and devices while observing meters and indicator lights.			

8.4 PowerCommand AC Protective Functions and Rationale

8.4.1 Design and Base Settings

PowerCommand generator sets incorporate, as standard, AC protective functions that in general are designed to protect the generator set and provide a nominal level of protection to the load without making a significant impact on reliability. The rationale used in defining the requirements is common for all controls, but the exact settings change somewhat from model to model of the control. The examples of settings used in this document are typical for all PowerCommand 3200 and 3201 controls.

8.4.2 Over Current Warning (51A)

Output current on any phase at more than 110% of rating for more than 60 seconds. (fixed) The warning function is provided to give an operator the opportunity to relieve the load on the alternator before it reaches a condition where it needs to shut down in order to protect itself. The control system can be set up to provide an external signal to command automatic load shedding on occurrence of this event. In most facilities it is rare for generators to operate at a power factor of less than 0.8, and the 10% and 60 second settings provides a level of protection against nuisance indication of a fault condition, even on a heavily loaded machine. Default alternator selections in Cummins production generator sets will always have at least a 10% overload capability to make it safe to use this function as a warning condition.

8.4.3 Over Current Shutdown (51)

Output current on any phase is more than 110%, less than 175% of rating, and approaching thermal damage point of alternator, as described on document R1053. The control includes algorithms to protect alternator by decreasing the shutdown time set point due to repeated over current conditions over a period of time which is insufficient to allow alternator cooldown before the fault re-occurs.

Overcurrent protection is the most critical protection function in an alternator protection scheme, because most modern alternators (those with excitation support systems such as permanent magnet generator driven voltage regulators) have the inherent ability to drive the alternator to destruction on a short circuit or ground fault condition. Thus, the overcurrent protection function must be matched to the thermal damage curve of the alternator. The control system does not allow adjustment of the alternator damage curve setting (in spite of the variation of alternator capability due to over-sizing for motor starting, etc.) because the function also provides code-required overload protection for a fully rated conductor set from the alternator to the first level of distribution. Also, the over-sizing of an alternator does not significantly change the time required to trip at a particular current level, so it is of very limited value to allow changing of this setting.

AmpSentry™ is the Cummins trade-marked name for the protection functions in the genset control. The control is UL-listed (category NRGU) as a utility grade protective relay.

In applications where a main breaker or paralleling breaker is used in series with the protection in a PowerCommand control, the downstream device should be set as a back up to the PowerCommand protection, since the genset controller is operating to protect the alternator with minimum impact on reliability. It is reasonable to set the paralleling breaker to specifically protect the conductors from the generator set to the paralleling breaker so that if there is an internal fault in the generator set short circuit current from the other generator sets in the system will not damage the conductors from the failing generator set to the paralleling breaker. Regardless of the settings of the downstream device, a contact indicating the breaker (or protective relay) is tripped should be connected to one of the genset customer fault inputs, and programmed to shut down the generator set and announce that the remote device has tripped.

8.4.4 Short Circuit Shutdown (51)

Output current on any phase is more than 110%, more than 175% of rating, and approaching thermal damage point of alternator, as described on R1053. Note that the settings and rationale for this protection function are the same as for over current, but the discrimination in alarm annunciation allows the user to understand the problem as a short circuit rather than something that might appear as a normally occurring overload condition, in a similar way to having the alternator provided with both a 51 and 51V protective function. (However, it is not rational to accelerate the tripping of an emergency generator faster on a short circuit than on an overload because the damage point is the same on either condition, and emergency machines are intended to remain on line until the point that they are about to be damaged under both types of conditions. Consider that generator sets, particularly on 3-phase faults have very limited fault current capability and may require additional time to clear downstream fault conditions.)

8.4.5 High AC Voltage Shutdown (59)

Output voltage on any phase exceeds preset values. Time to trip after the set point is achieved is inversely proportional to amount above threshold. Threshold values adjustable from 105-125% of nominal voltage, with time delay adjustable from 0.25-10 seconds. The trip time has an inverse characteristic to trip faster as voltage values increase. Tripping has no intentional time delay at 130% or more of alternator standard voltage. Default value is 110% for 10 seconds.

Over voltage conditions are not likely to damage a low voltage alternator, so this protective function should be considered to be a protective function for load devices in the system, which are likely to be damaged at voltage levels that are far lower than the level where alternator damage will occur. A voltage level that is maintained at less than 110% of setting is not likely to damage even sensitive electronic equipment, such as is described on the industry-standard ITI curve.

Over voltage conditions are a normal occurrence on an alternator when large blocks of load are suddenly dropped from the alternator. So, it is important that the setting not be so tight as to cause a nuisance shutdown of the machine (especially when the engine has been heavily loaded and may need a cooldown period in order to avoid damage to the engine.)

Over voltage damage to a typical medium voltage (>1000VAC) generator is possible on single phase fault, but PowerCommand generator sets include fault current regulation functions that prevent this event from occurring, and thus leave the over voltage function as primarily a load-protective function.

Dynamic testing of a generator set under various load and unload conditions replicating actual site conditions should be done at commissioning in order to establish if any changes are needed to these settings. This can also be done using sudden load drops from a load bank to establish that potentially damaging over voltage conditions do not occur

8.4.6 Low AC Voltage Shutdown (27)

Voltage on any phase has dropped below a preset value. Adjustable over a range of 50-95% of reference voltage, time delay 2-10 seconds. Default value is 85% for 10 seconds. Function tracks reference voltage to prevent nuisance tripping when synchronizing to a lower voltage source.

Under voltage does not damage a generator, but is generally indicative of an overload (kW) condition on the generator set. Under voltage conditions generally do not damage loads, but will cause them to misoperate.

This protective function should be coordinated with the overload alarm and shutdown settings on the generator set and the settings for the voltage roll-off functions in the voltage regulation system. Voltage roll-off (also termed “torque matching”) is a common control function integral to most voltage regulators that will cause the voltage to intentionally drop as frequency drops, in order to unload the engine and allow the engine to recover quickly from sudden kW load application or overload conditions.

Under voltage conditions are normal on a generator set, so the default settings are made to prevent nuisance tripping, and are not intended to be used to prevent misoperation of loads.

8.4.7 Under Frequency Shutdown (81u)

Generator set output frequency cannot be maintained. Settings are adjustable from 0-10 hertz below nominal governor set point, for a 0-20 second time delay. Default: 6Hz, 10 seconds.

Under frequency does not damage a generator, but is generally indicative of an overload (kW) condition on the generator set. It may also occur when the engine is unable to carry load normally due to incorrect settings, component failure, or fuel condition. This protective function, like under voltage, should be coordinated with the overload alarm and shutdown settings on the generator set and the settings for the voltage roll-off functions in the voltage regulation system. Under frequency is the most positive indication of overload on a generator and is valuable because it can detect an overload that is caused due to poor fuel condition or other events that occur whether or not a generator set is operating normally.

Under frequency is also a normally occurring event on a generator set, especially when large load steps are added to the generator set. The default settings are selected at a point that positively indicates a very adverse overload condition, and are unlikely to cause a nuisance tripping condition. Setting the under frequency set points “tighter” requires a clear understanding of normal load changes in the system and of the generator set’s response to these load changes. This alarm should not operate under normally occurring conditions in the facility distribution system. It should be checked on commissioning to be sure that nuisance shutdowns will not occur.

8.4.8 Over Frequency Shutdown/Warning (81o)

The control is adjustable for operation in a range of 0-10 hertz above nominal frequency, with a time delay of 0-20 seconds. Defaults: Disabled.

Over frequency is analogous to over speed in a synchronous generator set. The engine protection is commonly used to drive the protection of the engine, as it is more positively detected than frequency in generator sets that have electronic governing arrangements. (Frequency sensing can be disrupted by voltage waveform distortion and requires a longer period of time to sense than over speed, which is detected by the control by a magnetic pick-up monitoring the flywheel teeth on the engine.) Consequently, this function is disabled as a default on Cummins generator sets, and it is rarely used.

8.4.9 Over Load (kW) Warning

Provides a warning indication when engine is operating at a load level over a set point, and/or due to under frequency. Adjustment range: 50-140% of rated kW, 0-120 second delay. Defaults: 105%, 60 seconds. (Under frequency settings are noted above.)

This function is primarily used to signal load shedding in the system, so that the generator set can continue to operate and provide power to the most critical loads in the system. The US National Electrical Code requires this function be provided to protect the reliability of service to emergency and legally required loads in systems where the generator set also serves optional standby loads. It is also useful to provide load shedding in systems where generator sets power electric motor driven fire pumps to reduce generator set sizing, as is allowed by later versions of the US NEC.

The setting range allows the user to anticipate an overload condition and provide better protection for critical loads, as well as to respond to the specific dynamics of the facility where the equipment is installed. Default settings are designed to prevent nuisance indication of a problem, and are built around the concept that most Cummins generator sets can carry low level (<10%) overload conditions for a short period of time.

This is a function that should be set at the commissioning of the generator set, based on the ability of the generator set to carry load under site conditions and the expected nature of the dynamics of the load at the site.

8.4.10 Reverse Power Shutdown (32)

Adjustment range: 5-20% of standby kW rating, delay 1-15 seconds. Defaults: 10%, 3 seconds.

Reverse power protection for a generator set is critical in any situation where the generator set is paralleled, including applications where a generator set is applied with a closed transition transfer switch. (Failure modes in some switches can leave a generator set paralleled to the utility indefinitely, and aren’t detected by protection in the CTTS.) When a generator is paralleled with another source and looses the ability to provide real power (kW) to the system, the synchronous alternator reverts to effectively become a synchronous motor which drives the engine from power taken from other sources in the system. This may result in overloads on other sources in the system, and will result in severe (potentially catastrophic) damage to the engine if it is maintained for a long enough period of time.

The specific setting for the generator set should be done at generator commissioning based on site and generator set conditions. The setting magnitude should be made based on the magnitude of kW required to rotate the engine under reverse power conditions. This value is often as low as 5% of the standby rating of the genset, and is NOT equivalent to the regeneration limit published on engine data sheets.

Engines are not prone to failure over short time intervals due to a reverse power condition, and the load magnitude on the system during reverse power conditions does not often cause a system overload in a properly designed system. The setting also must be long enough to allow load share balancing between generators on a parallel bus to occur when a generator set initially closes to a bus or leaves the bus. This time is commonly less than 3 seconds but should be verified under actual conditions at a site. PowerCommand generator sets close to the bus and exit from the bus at no load under normal operating conditions, so timing may be somewhat tighter with these machines. Suggested settings for a multi-generator paralleling application with Cummins generator sets are typically 5% and 5 seconds.

The default settings in the control are selected to prevent nuisance tripping in a typical non-parallel application, and should be adjusted in any paralleling application.

8.4.11 Reverse VAR Shutdown (40)

Shutdown level is adjustable: threshold 0.15-0.50 per unit, delay 10-60 seconds. Defaults: 0.20, 10 seconds.

Reverse Var (loss of field) protection for a generator set is critical in any situation where the generator set is paralleled, including applications where a generator set is applied with a closed transition transfer switch. When a generator is paralleled with another source and looses the ability to provide reactive power (kVar) to the system, the magnetic field that maintains synchronous condition of the generator with the bus is lost, and the alternator can be severely damaged due to pole-slipping. This can occur in a very short period of time.

The maximum magnitude of the setting is dependant on the specific characteristics of the alternator provided in the system. In Cummins products, this ranges from approximately 20% to 50% of the genset rating. The 20% default value is suitable for protection of any alternator in our product line.

The time setting of 10 seconds is not sufficient to prevent a pole slip event, but is necessary to prevent nuisance shutdown of the genset on system starting in a paralleling application. In these conditions, especially in data center applications, it is common for lightly loaded UPS (or other equipment) to cause the generator set to operate at a leading power factor (reverse kVAR condition). As other generator sets synchronize and close the condition is often quickly relieved. However, if the system does experience a reverse kVar/loss of field shutdown and there is no hardware related damage found or evidence of overvoltage, it is possible that the set point for the trip can be increased based on the actual capability of the alternator, as is described on an alternator characteristic operating curve.

For generator sets that are not paralleled, the reverse var/loss of field protection is active, and will be useful in preventing overvoltage conditions that are induced in the machine as a result of reverse kVAR conditions that are caused by excessive capacitance in loads, such as from filters in a UPS system. In these applications the setting can be time delayed and increased to the acceptable limit of the reverse var capability of the alternator. Consult the factory for appropriate settings.

8.4.12 Phase Sequence Voltage (47) - (not adjustable)

The phase sequence voltage function is used in the genset paralleling application to verify that all bus phase voltages are available (proper magnitude) and phase sequence prior to synchronizing or connection of the generator set to the bus. Connection of a generator set to a bus with opposite phase sequence will cause immediate and serious damage to the machine.

8.4.13 Bus Voltage and/or Frequency Out of Range

Settings require bus voltage to be less than 10% or greater than 60% of generator set design voltage prior to the first generator closing to the bus, or turning on the generator synchronizer. These settings are not adjustable.

The protective function is designed to prevent an oncoming generator set from closing to a bus with voltage that is effectively unavailable, or operating under a severe fault condition. The control strategy is based on the premise that if bus voltage is abnormally low that condition will not endure indefinitely, and once cleared, the system can make an attempt to close remaining generator sets to the bus and re-energize the system. The 10% low setting deals with the situation where a “ghost” voltage appears on the control system due to conditions in the system design.

8.5 Codes and Standards

Although there are no codes or standards written expressly for paralleling equipment, a number of standards are typically referenced in projects that involve paralleling equipment.

- IEC61439 low voltage equipment; Asian markets in general are open to both Non-Type Tested and IEC 60439-1 Type Tested switchgear.
- Australia and New Zealand equipment must comply with AS/NZS 3439.1, which is an extension of IEC 60439.
- IEC 60439-1994 Low voltage switchgear and control assemblies
- IEC 61439-2009 Low voltage switchgear and control assemblies
- BS EN 60439-1994 Low voltage switchgear and control assemblies
- BS EN 61439-2009 Low voltage switchgear and control assemblies
- CCC Certification in (Peoples Republic of China)
- UL 891 low voltage switchboards
- UL 1558 low voltage switchgear (generally validates a design for compliance to C37.20.1)
- ANSI/IEEE C37.20.1, Metal Enclosed Low Voltage Power Circuit Breaker Switchgear
- ANSI/IEEE C37.0.2, Metal Clad Switchgear (medium voltage)
- UL 1670 medium voltage switchgear (generally validates a design for compliance to C37.20.2)
- ANSI/IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems

8.5.1 ANSI

The American National Standards Institute (ANSI) does not develop standards, but does serve as a national coordinator of voluntary standards activities, as an approval organization, and as a clearinghouse for consensus standards. Approval by ANSI validates the general acceptability of the work of the standard developer. ANSI approval indicates that the standards writing group used democratic procedures that gave everyone who will be directly and materially affected by the use of the standard an opportunity to participate in the development work or to comment on the standard's provisions. ANSI approval notifies users that these interests reached consensus on the standard's provisions and that the document is technically sound and does not conflict with or necessarily duplicate other national standards.

ANSI C37.20 originally covered all switchgear assemblies. As the industry evolved various sections were broken out and identified by their own standards. The two standards that are most relevant to Cummins Power Generations are ANSI/IEEE C37.20.1 IEEE Standard for Metal-Enclosed Low-Voltage Circuit Breaker Switchgear and ANSI/IEEE C37.20.2 IEEE Standard for Metal-Clad Switchgear. IEEE C37.20.1 covers switchgear with voltage ratings up to 635 V ac and current ratings up to 12,000 A. IEEE C37.20.2 is generally applied to medium voltage switchgear with voltage ratings up 38kV with current ratings up to 3000 amps. Some of the defining characteristics of metal clad switchgear as defined by IEEE C37.20.2 are that all live components are completely enclosed by grounded metal barriers and bus bars are fully insulated.

8.5.2 ANSI/NEMA ICS-21983 and NEMA MG1-1988

Cummins Power Generation is a member company of two sections, Industrial Control Systems Section and Motor Generator Section, within the National Electrical Manufacturers Association (NEMA). NEMA publishes extensive electrical equipment standards, including ICS 2-447, Transfer Switch Equipment, which includes applicable provisions for automatic and non automatic transfer switches, and bypass-isolation switches. The Industrial Control and Systems Section (ICS) formed a subcommittee of manufacturers (including Cummins Power Generation) of generator paralleling equipment in 1987. NEMA also publishes MG1-1988, Motors and Generators, which includes applicable provisions for synchronous generators.

8.5.3 ANSI/NFPA 70 National Electrical Code

The National Electric Code includes many references to requirements that are typical for all electrical equipment and its installation. It also draws a distinction between conventional transfer switches and paralleling equipment, which includes power transfer functions. (See article 230–83 for references to requirements for transfer switches and paralleling transfer equipment).

Cummins Power Generation paralleling load transfer equipment is intended for use in emergency and legally required standby power systems, in accordance with National Electric Code articles 700, 701, and 517.

Article 705, *Interconnected Electric Power Production Sources*, covers the installation of one or more electric power production sources operating in parallel with a primary source of electricity. Functionally, a non–load break load transfer system causes the generator set to parallel with the utility on a momentary basis. The code does not restrict its applicability by duration of the parallel period. Load transfer equipment that includes utility paralleling functions must comply with the provisions of article 705.

Following are the major requirements of 705, along with our comments as to their interpretation (requirements are in italics):

1. *Permanent plaques or directories must be provided at each service entrance, noting all electrical sources in the facility.* These plaques should specifically direct the user to shut down and lock out the on–site generator set when working on the system.
2. *The interconnection of the on–site power source and the utility must be at the service entrance of the facility unless all of the following conditions are met:*
   - *The generator set is larger than 100kW (or operates at more than 1000volts).*
   - *Steps are taken to be sure that equipment is adequately supervised and maintained.*
   - *Safeguards and protective equipment are provided and maintained.*

     Protective equipment includes adequate protective relaying, which is provided in compliance to utility requirements and good engineering judgment. For a system of the size, cost, and complexity of the equipment normally provided by Cummins Power Generation; this equipment would include overvoltage and undervoltage, overfrequency and underfrequency, phase sequence, and reverse power protective relaying.

3. *Consideration must be given to the ground fault protective system so that it functions properly with interconnected sources.* For most systems rated 1000 amps and higher, ground fault protection is required on the normal (utility) service, and ground fault alarms are required for the on–site power system. For health care facilities where ground fault is required, a coordinated multiple level system is required. In most installations, this will require use of separate ground fault equipment, rather than using breakers with integral ground fault trips. This also requires careful consideration of the grounding method for the generator set.
4. *Loss of the normal service or loss of a single phase must force the generator set to be disconnected from the utility service.* Without utility grade protective relaying to sense this power loss, this failure may not be sensed.
5. *Synchronous generator sets must be provided with equipment that enables them to establish and maintain a synchronous interconnection.* To establish parallel operation is not difficult. This can be accomplished with nothing more than a synchronizing check relay. (Cummins Power Generation recommends the use of active synchronizing equipment to provide predictable, reliable system performance.)

   To maintain interconnection, real and reactive load sharing equipment must be added to the system. This is critical if the on–site power system is connected to the utility service for an extended period of time, either purposefully, or due to misoperation of the transfer device.

8.5.4 ANSI/NFPA 110, NFPA 99

The National Fire Protection Association (NFPA) publishes a large number of codes and standards intended for protection of life and property from fire. These include NFPA 110, Emergency and Standby Power Systems and NFPA 99, Standard for Health Care Facilities. NFPA 110 includes applicable provisions for the performance of on-site power systems intended to provide electrical power for life safety purposes when the normal power supply fails.

The scope of NFPA 110 includes on-site power sources, paralleling equipment, transfer equipment, and all related mechanical and electrical auxiliary equipment (excluding distribution wiring) up to the load terminals of the transfer equipment. Included are installation, maintenance, operation, and testing requirements, as they pertain to system performance.

NFPA 99 is more general, with respect to emergency system requirements.

Although there are only a few direct references to paralleling equipment in these standards, many of the requirements for generator sets and transfer switches, and the emergency system in general, have an impact on paralleling equipment design.

Some of the most notable requirements of NFPA 110 are:

- Generator sets are required to have a relatively complex control panel, with very specific control, alarm indication, and AC metering features. This control panel is to be mounted on the generator set, or in the immediate vicinity of the generator set. Cummins Power Generation's position is that a generator control mounted in the paralleling equipment does not meet this requirement. (See section 3-5.5 for complete details.) The emergency system must include an exerciser clock. In a single generator/ATS system, this would be normally mounted in the transfer switch. However, in a paralleling system, the most logical location for the exerciser clock is in the paralleling equipment master/totalizing control panel. (See section 3-5.5.1.)
- Complete system electrical drawings and interconnect details must be provided (3-5.9.6).

- An emergency manual stop/break glass station is required. We recommend that this should shut down the entire generator system from one station (3-5.5.5).
- The emergency system is required to have a controlled load priority (load adding) and load shedding system, to prevent overload of the generator system, if a portion of the system fails (4-3).
- The system is required to be provided with emergency battery powered lighting for the generator and control areas (5.3).
- The system is required to be tested at the site at full load. If not tested at the factory at 0.8 power factor, it must be tested at the site at 0.8 power factor (5-13.2.5).
- The standard includes detailed maintenance recommendations and requirements (section 6).
- The most important requirements of NFPA 99, with respect to paralleling equipment, are:
- Life safety and critical loads are required to be fed within 10 seconds after a power failure (3-3.2.1.8). In order to perform to this level, the system should be designed so that any one generator set is capable of picking up all life safety and critical loads. Although it is possible (under ideal conditions) to start and parallel generator sets within this time, many applications do not require that the entire system perform to this level.
- Remote alarm annunciators must be provided (3-3.2.1.15). Because the standards are written with only one generator set in mind, the remote annunciation requirement does not reflect paralleling equipment alarm functions, which may be desirable in remote monitoring stations.

8.5.5 ANSI/UL 1008

Underwriter's Laboratories (UL) is an independent testing laboratory and publishes product safety standards, including UL 1008, Transfer Switch Equipment. UL 1008 contains important construction, performance, and marking requirements; and a testing protocol, specifically written for transfer switch equipment. Cummins Power Generation transfer switch equipment has been investigated by UL, found to comply with the requirements of UL 1008, and is Listed for installation in Emergency and Legally Required Standby Power Systems according to National Electrical Code Articles, 700, 701, and 517.

Transfer switches installed in paralleling/distribution equipment line-ups should be UL1008 listed, even though the structure is usually listed under other UL standards.

8.5.6 ANSI/UL Paralleling Equipment Standards

Two UL standards are typically specified for paralleling/distribution equipment, UL891 and UL1558. Requirements are designed particularly to provide safety for the operator, and do not address control system reliability or performance. Also, they do not address generator controls, or the total system performance, as is done with NFPA 110.

Provided that the application is for equipment rated 100,000 amperes or less, either UL891 or UL1558 may be used to verify the safety of the design used. Over 100,000 amperes, testing is required to verify the safety of the equipment by either standard. In both cases, the UL label is prima facie evidence of UL's approval of the safety of the basic design.

The overall rating of the switchgear assembly is limited to the interrupting capacity of the lowest rated device connected to the bus. In other words, the buswork of a switchgear assembly could be braced to 100,000 amperes, but if the breakers used were rated at 30,000 amperes, the switchgear would have a short circuit rating of 30,000 amperes.

The premise of the design standards generated by UL, NEMA, ANSI, etc. is that the switchgear should be able to safely withstand a SINGLE fault at the rating level. No standard specifically addresses the durability of equipment when exposed to multiple faults at, or close to, the rating level of the equipment.

Switchgear built to current standards is not guaranteed to operate successfully after a major fault. (The purpose of the standard is to prevent a failure of the system that would result in safety hazards, such as fires-not to guarantee operational integrity).

If any system, regardless of the design standard used to qualify its construction, were exposed to high fault current levels, proper practice would require the disassembly and inspection (and probably rebuilding) of the system prior to its continued use.

Cummins Power Generation can provide equipment that is either UL891 or UL1558 listed, depending on project requirements.

8.5.7 UL 891

The most common standard for paralleling equipment is UL891, Dead Front Switchboards. It contains construction and performance requirements and a test protocol to cover switchboards for the control of electric light and power circuits.

Regarding short circuit tests, switchboards may be tested to establish ratings, or they may be designed to specified construction requirements to establish a rating without a short circuit test. The construction standard is very conservative. Testing of a specific design allows a manufacturer to reduce system cost, and still meet the requirements of the standard.

Either method (test or build to spec) is considered by UL to result in equal levels of safety of the equipment. In view of the conservative nature of the construction standard, it may result in designs that perform significantly better than those developed through the testing process.

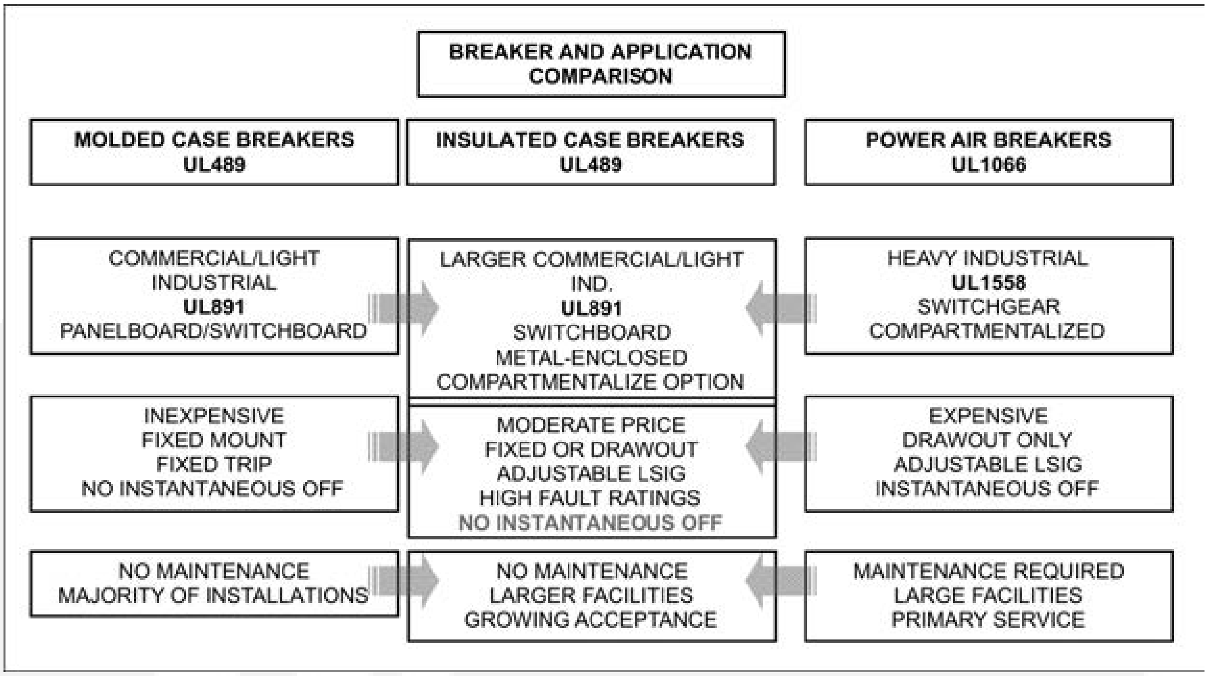
UL891 allows listing of paralleling equipment with bracing levels of up to 100,000 amperes using the construction standard or testing standard; it allows listings with bracing levels of up to 200,000 amperes using the testing procedure.

Cummins Power Generation random access paralleling switchboards have been investigated by UL and found to comply with the requirements of UL 891, and are UL Listed.

8.5.8 UL 1558

Metal-Enclosed Low-Voltage Power Circuit Breaker Switchgear, UL 1558, contains supplementary requirements to be used in conjunction with those of Metal-Enclosed Low-Voltage Power Circuit Breaker Switchgear, ANSI C37.20.1 and Conformance Testing of Metal-Enclosed Low-Voltage Power Circuit Breaker Switchgear, ANSI C37.51. UL 1558 is not intended to be used by testing laboratories as a standalone document for evaluation purposes.

UL1558 was originally developed as a standard for low voltage distribution switchgear composed of drawout power circuit breakers. Subsequent changes have allowed the listing under this standard with molded case breakers, and other devices-based on the supplier's approval process. Consequently, there is no significant difference in the actual hardware provided, based on the use of UL891 or UL1558.



8.5.9 UL 1670

UL 1670 was written to provide third party certification of the design and manufacturing of switchgear and circuit breakers that operate at over 600 volts. UL 1670 relies heavily on ANSI C37.54 - 1987 (*Indoor AC High Voltage Circuit Breakers Applied as Removable Elements in Metal-clad Switchgear Assemblies - Conformance Testing Procedures*) and ANSI C37.55 - 1989 (*Metal-clad Switchgear Assemblies - Conformance Testing Procedures*). The standard addresses switchgear that can be used at 4.76, 8.25, 15, or 38 kilovolts, with continuous circuit breaker ratings of 1200, 2000, or 3000 amps. The circuit breaker short circuit ratings range from 250-1000 MVA.

There is no significant difference in equipment that complies with the referenced ANSI standards and equipment that is UL 1670 labeled.

8.5.10 ANSI/IEEE1547 - Standard for Interconnecting Distributed Resources with Electric Power Systems.

IEEE 1547 is the U.S. standard specifying the technical requirements for and testing of the interconnection between distributed power generation equipment and the utility. It includes general requirements, response to abnormal conditions, power quality, islanding and requirements for design, production, installation evaluation, commissioning, and periodic tests.

8.6 ANSI Device Descriptions

The following descriptions are derived from IEEE C37.2 (revised 2001)

TABLE 18. ANSI DEVICE DESCRIPTIONS

Device Number	Function and Description
1	Master Element is the initiating device, such as a control switch, voltage relay, float switch, etc., which serves either directly or through such permissive devices as protective and time-delay relays to place equipment in or out of operation.
2	Time-Delay Starting or Closing Relay is a device that functions to give a desired amount of time delay before or after any point of operation in a switching sequence or protective relay system, except as specifically provided by device functions 48, 62, and 79.
12	Over-Speed Device is usually a direct-connected speed switch which functions on machine overspeed.
15	A device that forces operating equipment to match and hold the speed of another machine or source of power.
20	Valve is one used in a vacuum, air, gas, oil, or similar line, when it is electrically operated or has electrical accessories such as auxiliary switches.
21	Distance Relay is a relay that functions when the circuit admittance, impedance, or reactance increases or decreases beyond predetermined limits.
25	Synchronizing or Synchronism-Check Device is a device that operates when two AC circuits are within the desired limits of frequency, phase angle, or voltage, to permit or to cause the paralleling of these two circuits.
27	Undervoltage Relay is a relay that functions on a given value of undervoltage.
31	Annunciator Relay is a nonautomatically reset device that gives a number of separate visual indications upon the functioning of protective devices, and which may also be arranged to perform a lockout function.
32	Directional Power Relay is a device that functions on a desired value of power flow in a given direction or upon reverse power resulting from arc-back in the anode or cathode circuits of a power rectifier.
33	Position Switch is a switch that makes or breaks contact when the main device or piece of apparatus which has no device function number reaches a given position.
37	Undercurrent or Underpower Relay is a relay that functions when the current or power flow deceases below a predetermined value.
40	Field Relay is a relay that functions on a given or abnormally low value or failure of machine field current, or on an excessive value of the reactive component of armature current in an AC machine indicating abnormally low field excitation.
41	Field Circuit Breaker is a device that functions to apply or remove the field excitation of a machine.
42	Running Circuit Breaker is a device whose principal function is to connect a machine to its source of running or operating voltage. This function may also be used for a device, such as a contactor, that is used in series with a circuit breaker or other fault protecting means, primarily for frequent opening and closing of the circuit.
43	Manual transfer or Selector Device is a manually operated device that transfers the control circuits in order to modify the plan of operation of the switching equipment or of some of the devices.
44	Unit Sequence Starting Relay is a relay that functions to start the next available unit in a multiple-unit equipment upon the failure or nonavailability of the normally preceding unit.
46	Reverse-Phase or Phase-Balance Current Relay is a relay that functions when the polyphase currents are of reverse-phase sequence, or when the polyphase currents are unbalanced or contain negative phase-sequence components above a given amount.
47	Phase-Sequence Voltage Relay is a relay that functions upon a predetermined value of polyphase voltage in the desired phase sequence.

Device Number	Function and Description
48	Incomplete Sequence Relay is a relay that generally returns the equipment to the normal, or off, position and locks it out if the normal starting, operating, or stopping sequence is not properly completed within a predetermined time. If the device is used for alarm purposes only, it should preferably be designated as 48A (alarm).
50	Instantaneous Overcurrent or Rate-of-Rise Relay is a relay that functions instantaneously on an excessive value of current or on an excessive rate of current rise, thus indicating a fault in the apparatus or circuit being protected.
51	AC Time Overcurrent Relay is a relay with either a definite or inverse time characteristic that functions when the current in an AC circuit exceeds a predetermined value.
52	AC Circuit Breaker is a device that is used to close and interrupt an AC power circuit under normal conditions or to interrupt this circuit under fault or emergency conditions.
55	Power Factor Relay is a relay that operates when the power factor in an AC circuit rises above or falls below a predetermined value.
56	Field Application Relay is a relay that automatically controls the application of the field excitation to an AC motor at some predetermined point in the slip cycle.
57	Short-Circuiting or Grounding Device is a primary circuit switching device that functions to short-circuit or to ground a circuit in response to automatic or manual means.
58	Rectification Failure Relay is a device that functions if one or more anodes of a power rectifier fail to fire, or to detect an arc-back or on failure of a diode to conduct or block properly.
59	Overvoltage Relay is a relay that functions on a given value of overvoltage.
60	Voltage or Current Balance Relay is a relay that operates on a given difference in voltage, or current input or output, of two circuits.
62	Time-Delay Stopping or Opening Relay is a time-delay relay that serves in conjunction with the device that initiates the shutdown, stopping, or opening operation in an automatic sequence or protective relay system.
64	Ground Protective Relay is a relay that functions on failure of the insulation of a machine, transformer, or of other apparatus to ground, or on flashover of a DC machine to ground.
	NOTE: This function is assigned only to a relay that detects the flow of current from the frame of a machine or enclosing case or structure of a piece of apparatus to ground, or detects a ground on a normally ungrounded winding or circuit. It is not applied to a device connected in the secondary circuit of a current transformer, or in the secondary neutral of current transformers, connected in the power circuit of a normally grounded system.
65	Governor is the assembly of fluid, electrical, or mechanical control equipment used for regulating the flow of water, steam, or other medium to the prime mover for such purposes as starting, holding speed or load, or stopping.
67	AC Directional Overcurrent Relay is a relay that functions on a desired value of AC overcurrent flowing in a predetermined direction.
68	Blocking Relay is a relay that initiates a pilot signal for blocking of tripping on external faults in a transmission line or in other apparatus under predetermined conditions, or cooperates with other devices to block tripping or to block reclosing on an out-of-step condition or on power savings.
69	Permissive Control Device is generally a two-position, manually-operated switch that, in one position, permits the closing of a circuit breaker, or the placing of equipment into operation, and in the other position prevents the circuit breaker or the equipment from being operated.
70	Rheostat is a variable resistance device used in an electric circuit, which is electrically operated or has other electrical accessories, such as auxiliary, position, or limit switches.
74	Alarm Relay is a relay other than an annunciator, as covered under device function 30, that is used to operate, or to operate in connection with a visual or audible alarm.
77	Pulse Transmitter is used to generate and transmit pulses over a telemetering or pilot-wire circuit to the remote indicating or receiving device.

Device Number	Function and Description
78	Phase-Angle Measuring or Out-of-Step Protective Relay is a relay that functions at a predetermined phase angle between two voltages or between two currents or between voltage and current.
79	A-C Reclosing Relay is a relay that controls the automatic reclosing and locking out of an a-c circuit interrupter.
80	Liquid or Gas Flow Relay is a relay that operates on given values of liquid or gas flow or on given rates of change of these values.
81	Frequency Relay is a relay that functions on a predetermined value of frequency (either under or over or on normal system frequency) or rate of change of frequency.
82	D-C Reclosing Relay is a relay that controls the automatic closing and reclosing of a d-c circuit interrupter, generally in response to load circuit conditions.
83	Automatic Selective Control or Transfer Relay is a relay that operates to select automatically between certain sources or conditions in an equipment or performs a transfer operation automatically.
84	Operating Mechanism is the complete electrical mechanism or servomechanism, including the operating motor, solenoids, position switches, etc. for a tap changer, induction regulator, or any similar piece of apparatus which otherwise has no device function number.
85	Carrier or Pilot-Wire Receiver Relay is a relay that is operated or restrained by a signal used in connection with carrier-current or d-c pilot-wire fault directional relaying.
86	Locking-Out Relay is an electrically operated hand, or electrically reset relay or device that functions to shut down or hold and equipment out of service, or both, upon the occurrence of abnormal conditions.
87	Differential Protective Relay is a protective relay that functions on a percentage or phase angle or other quantitive difference of two currents or of some other electrical quantities.
88	Auxiliary Motor or Motor Generator is one used for operating auxiliary equipment, such as pumps, blowers, exciters, rotating magnetic amplifiers, etc.
89	Line Switch is a switch used as a disconnecting, load-interrupter, or isolating switch in an a-c or d-c power circuit, when this device is electrically operated or has electrical accessories, such as an auxiliary switch, magnetic lock, etc.
90	Regulating Device is a device that functions to regulate quantity, or quantities, such as voltage, current, power, speed, frequency, temperature, and load, at a certain value or between certain (generally close) limits for machines, tie lines or other apparatus.
91	Voltage Directional Relay is a relay that operates when the voltage across an open circuit breaker or contactor exceeds a given value in a given direction.
92	Voltage and Power Directional Relay is a relay that permits or causes the connection of two circuits when the voltage difference between them exceeds a given value in a predetermined direction and causes these two circuits to be disconnected from each other when the power flowing between them exceeds a given value in the opposite direction.
93	Field-Changing Contactor is a contactor that functions to increase or decrease, in one step, the value of field excitation on a machine.
94	Tripping or Trip-Free Relay is a relay that functions to trip a circuit breaker, contactor, or equipment, or to permit immediate tripping by other devices; or to prevent immediate reclosure of a circuit interrupter if it should open automatically even though its closing circuit is maintained closed.

8.6.1 ANSI Representation of PowerCommand Control

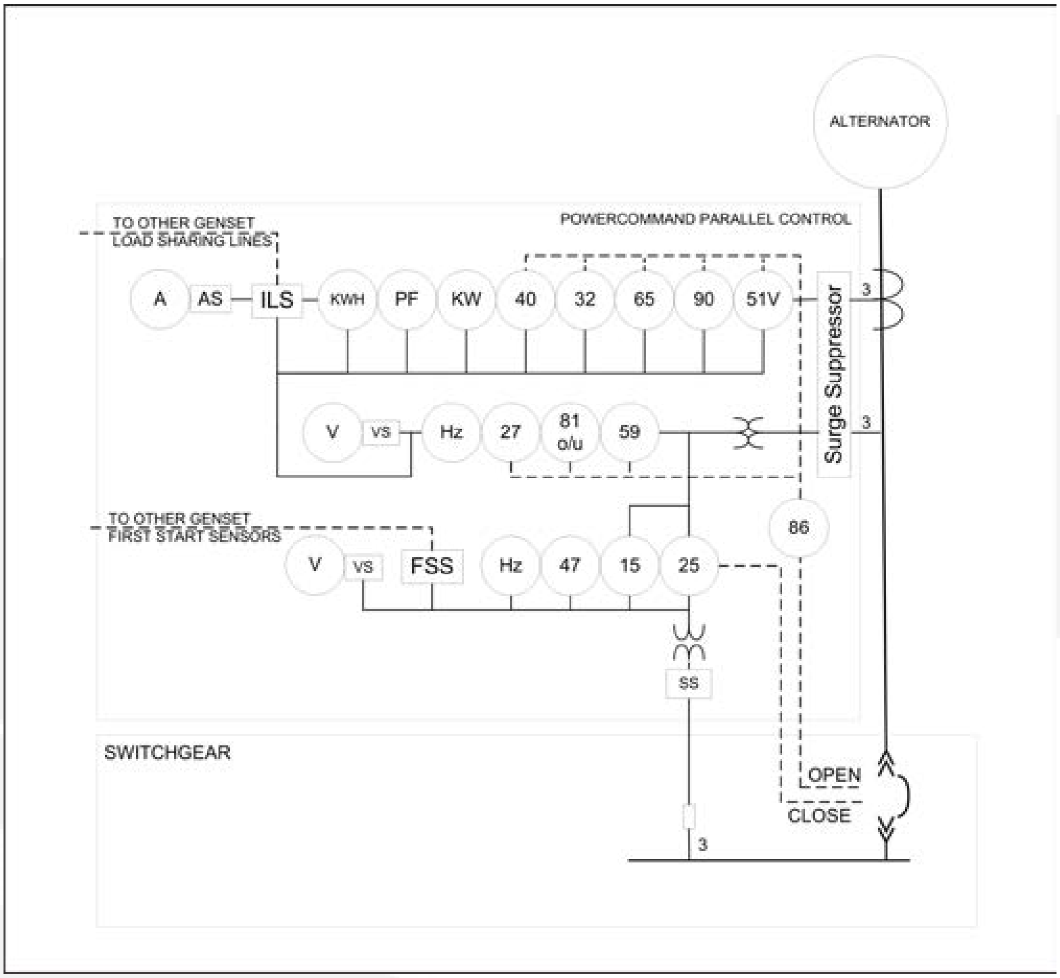


FIGURE 106. ANSI REPRESENTATION OF POWERCOMMAND CONTROL.

8.6.2 ANSI Representation of MCM 3320 Control

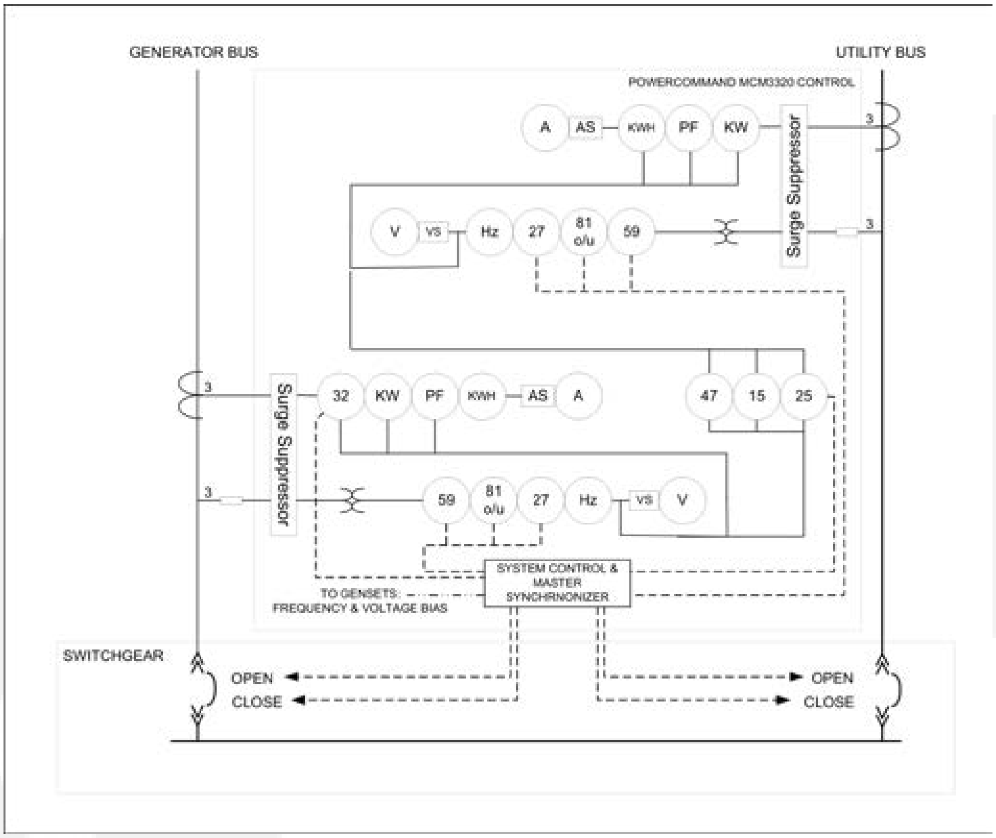


FIGURE 107. ANSI REPRESENTATION OF MCM 3320 CONTROL

8.7 Glossary

Active Power

Active power is the real power (kW) supplied by the generator set to the electrical load. Active power creates a load on the set's engine and is limited by the power of the engine and efficiency of the generator. Active power does the work of heating, lighting, turning motor shafts, etc.

Air Circuit Breaker

An air circuit breaker automatically interrupts the current flowing through it when that current exceeds the trip rating of the breaker. Air is the medium of electrical insulation between electrically live parts and grounded (earthed) metal parts. Also see Power Circuit Breaker.

Annunciator

An annunciator is an accessory device used to give remote indication of the status of an operating component in a system. Annunciators are typically used in applications where the equipment monitored is not located in a portion of the facility that is normally attended. The NFPA has specific requirements for remote annunciators used in some applications, such as hospitals.

ANSI

American National Standards Institute.

Authority Having Jurisdiction

The authority having jurisdiction is the individual with the legal responsibility for inspecting a facility and approving the equipment in the facility as meeting applicable codes and standards.

Automatic (Exciter) Paralleling

Automatic (exciter) paralleling describes a system where two or more generator sets can be started and paralleled while coming up to rated frequency and voltage. Because the generator excitation system is not turned on until the generator set is started (thus the term "dead field") , the generator sets automatically synchronize as they come to rated speed and voltage. In Cummins Power Generation automatic exciter paralleling systems, only manual paralleling to a live bus is possible.

AVR

Automatic voltage regulator. In the context of this document, this term applies to an electronic device that measures voltage on the output of an alternator and regulates the main field of the machine to maintain constant voltage with variable load.

Black Start

Black start refers to the starting of a power system with its own power sources, without assistance from external power supplies.

Bracing Rating

For switchboard/switchgear equipment, the bracing rating describes the maximum symmetrical fault current that the equipment is designed to carry without damage to the switchboard/switchgear structure.

Bus

Bus can refer to the devices that connect the generators and loads in a paralleling system, or to the paralleled output of the generators in a system.

Bus Bars

Bus bars are rectangular copper or aluminum bars that connect the output of the generator set circuit breakers to the transfer switches, circuit breakers, or fusible switches that transfer power to the loads. The bus bars are sized and assembled in multiples according to the current they must carry. There is one bar for each phase and for the neutral (if neutral is used). A typical sizing criteria for copper bus bars rated from 500-5000 amps is to maintain a current density of 1000 amps per square inch of cross sectional area. This results in a bus temperature rise at full load that is within acceptable limits.

Bus Capacity

Bus capacity is the maximum load that can be carried on a system without causing degradation of the generator frequency to less than a prescribed level (usually 59 Hz in a 60 Hz system).

CCT

CCT is an abbreviation for Cross Current Transformer. Current Transformers are used to step down the higher line current to the lower currents that the control system is designed for.

Circulating Harmonic Currents

Circulating harmonic currents are currents that flow because of differences in voltage waveforms between paralleled power sources, or induced by operation of non-linear loads.

Common Bus (Paralleling System)

A common bus paralleling system is one in which multiple generators are configured to parallel with a utility with no generator main breaker available to isolate the generator bus.

Cross Current Compensation

Cross current compensation is a method of controlling the reactive power supplied by AC generators in a paralleling system so that they share equally the total reactive load on the bus without significant voltage droop.

Cross Currents

Cross currents are currents that circulate between paralleled generator sets when the internal (excitation) voltage of one set is different from the other set (or sets). The set with the higher internal voltage supplies reactive power (kVAR) to the other set (or sets). The amount of cross current that flows is a measure of this reactive power. Cross currents are 90 degrees out of phase (lagging) compared to the current that the generator would supply at 1.0 (unity) power factor.

Dead Bus

Dead bus refers to the de-energized state of the power connections between outputs of paralleled generator sets. The term bus in this usage can either be rigid solid bus bars or insulated flexible cables.

Dead Field Paralleling

See Automatic (Exciter) Paralleling.

Differential Relay

A differential relay is a protective device which is fed by current transformers located at two different series points in the electrical system. The differential relay compares the currents and picks up when there is a difference in the two which signifies a fault in the zone of protection. These devices are typically used to protect windings in generators or transformers.

Distribution Circuit Breaker

A distribution circuit breaker is a device used for overload and short current protection of loads connected to a main distribution device.

Distribution Switchgear

Distribution switchgear may include automatic transfer switches, drawout air frame circuit breakers, fusible switches, or molded case breakers.

DMSU

Demand mode standby unit (or units) are generator sets that can be shut down by the system when there is a low load level on the system.

Draw Out Unit

A draw out unit is a structure that holds a circuit breaker in an enclosure. It has a movable carriage and contact structures that permit the breaker to be removed from the enclosure without manually disconnecting power cables and control wires.

Droop Load Sharing

Droop load sharing is a method of making two or more parallel generator sets share a system kW load. This is accomplished by having each governor control adjusted so that the sets have the same droop (reduction of speed). Typical droop is two cycles in frequency from no load to full load.

Dual Transfer Pair (Paralleling System)

A dual transfer pair paralleling system is a paralleling system in which there are two utility feeds separated by circuit breakers from a generator bus. The generator bus backs up both utility feeds. The system is similar to two transfer pair systems that share a generator bus.

Earth Fault Protection

See Ground Fault Protection.

Earthing or Grounding

Earthing is the intentional connection of the electrical system or electrical equipment (enclosures, conduit, frames, etc) to earth or ground.

Earthing or Grounding Bar

A grounding bar is a copper bar that electrically joins all the metal sections of the switchgear. This bar is connected to the earth or ground connection when the system is installed. The grounding (earthing) protects personnel from stray currents that could leak to the metallic enclosures.

Electrical Operator

An electrical operator is the electric motor driven closing and tripping (opening) devices that permit remote control of a circuit breaker.

Emergency Bus

An emergency bus is the silver-plated copper bus bars or flexible cable used to connect the paralleling breakers to the emergency system feeder breakers, and ultimately to automatic transfer switches or other distribution devices.

Emergency (System, Load, Equipment, etc.)

An emergency system is independent power generation equipment that is legally required to feed equipment or systems whose failure may present a life safety hazard to persons or property.

Exciter

An exciter is a device that supplies direct current (DC) to the field coils of a synchronous generator, producing the magnetic flux required for inducing output voltage in the armature coils (stator). See Field.

Exciter Paralleling Control

An exciter paralleling control initiates the start of generator excitation in generator sets used in automatic paralleling systems.

Fault

A fault is any unintended flow of current outside its intended circuit path in an electrical system.

Feeder Circuit Breaker

See Distribution Circuit Breaker.

Field

The generator field (rotor) consists of a multi–pole electromagnet which induces output voltage in the armature coils (stator) of the generator when it is rotated by the engine. The field is energized by DC supplied by the exciter.

Field Breaker with Auxiliary Switch

This is the circuit breaker (usually mounted in the generator control panel) that monitors the alternating current input to the automatic voltage regulator. If a malfunction occurs in the excitation system, the circuit breaker trips on overcurrent-closing the auxiliary switch, shutting down the generator set, and energizing the alarm circuit.

First Start Sensor

A first start sensor is an electronic device within Cummins Power Generation OSPS and SSPS paralleling equipment that senses generator set and bus voltage and frequency, and determines whether or not a generator set is the first unit ready to close to the bus following a call to start under "black start" conditions.

Frequency Adjust Potentiometer

A frequency adjust potentiometer is used to manually bring the frequency (speed) of the incoming set to that of the bus for synchronizing purposes. When the generator set is paralleled, operation of this potentiometer will adjust the kW load assumed by the generator set.

Fusible Switch

A fusible switch is an isolating switch and overcurrent protective device used for feeder or transfer switch isolation and protection. It is typically a manually operated, stored energy opening and closing, bolted compression blade switch, with provisions for installing current limited fuses.

Generator Bus Main Breaker

An electrically operated circuit breaker whose primary purpose is to connect a paralleling generator bus to loads.

Generator Paralleling Breaker

An electrically operated circuit breaker whose primary purpose is to connect a synchronized generator set to a paralleling bus.

Governor

A governor is a device on the engine which controls fuel to maintain a constant engine speed under various load conditions. The governor must have provision for adjusting speed (generator frequency) and speed droop (no load to full load).

Grid

The utility-owned power distribution system.

Ground

A ground is a connection, either intentional or accidental, between an electrical circuit and the earth or some conducting body serving in place of the earth.

Grounded Neutral

A grounded neutral is the intentionally grounded center point of a Y–connected, four–wire generator, or the mid–winding point of a single phase generator.

Ground Fault Protection

This function trips (opens) a circuit breaker or sounds an alarm in the event that there is an electrical fault between one or more of the phase conductors and ground (earth). This ground fault protection function may be incorporated into a circuit breaker.

Grounding

Grounding is the intentional connection of the electrical system or the electrical equipment (enclosures, conduit, frames etc.) to earth.

Grounding Bar

A grounding bar is a copper bar that electrically joins all the metal sections of the switchgear. This bar is connected to the earth or ground connection when the system is installed. The grounding (earthing) protects personnel from stray currents that could leak to the metallic enclosures.

Hard Closed Transition

A hard closed transition is a transfer of power from one source to another during which there is a period of time not to exceed 100 msec when both sources are simultaneously connected to the load. Also called fast closed transition.

Harmonic Distortion (Total Harmonic Distortion)

Total harmonic distortion is an expression of the total harmonic content of a voltage waveform. The harmonic distortion (or harmonic content) of a waveform is usually expressed as the square root of the sum of the squares of each of the harmonic amplitudes (with amplitude as a percent of the fundamental voltage amplitude).

Harmonics

Harmonics are voltage or current components which operate at integral multiples of the fundamental frequency of a power system (50 or 60 Hertz). Harmonic currents have the effect of distorting the shape of the voltage wave form from that of a pure sine wave.

IEC

International Electrotechnical Commission. Organization that publishes international standards for electrical and electronic products.

Import/Export Control

An import/export control is an electronic device used in utility paralleling systems to actively control the amount of electrical power created by a generator set operating in parallel with the utility service.

Incoming Set

This is the generator set that is about to be connected to (paralleled with) the energized bus.

Insulated Case Circuit Breaker

An insulated case circuit breaker is a power circuit breaker that is provided in a preformed case, similar to a molded case breaker.

Internal Voltage

The internal voltage is the voltage a generator would develop at no load if it were not connected in a parallel operation. Excitation of the generator field controls internal voltage.

Interruptible

This refers to the practice of operating on-site power systems, at the request of a utility, to reduce electrical demand on the utility grid during periods of high consumption. Interruptible facilities may also be disconnected from all electrical service in the event of high demand on the utility grid, even if no on site power system is available.

Interrupting Capacity

Interrupting capacity is the magnitude of electrical current that a device can safely interrupt (open against), without failure of the component.

Isochronous Load Sharing (ILS)

ILS is a method of controlling the speed of paralleled generator sets so that all sets share the load equally, without any droop in frequency. This is accomplished with electronic governors controlled from isochronous load sharing modules contained in the individual paralleling controls. ILS usually refers to the electronic component that provides this function.

Isolated Bus (Paralleling System)

An isolated bus paralleling system is a paralleling system in which at no time are the generators sets electrically connected to the utility.

kVA (kilo–Volt–Amperes)

kVA is a term for rating electrical devices. A device's kVA rating is equal to its rated output in amperes multiplied by its rated operating voltage. In the case of three–phase generator sets, kVA is the kW ouput rating divided by 0.8, the rated power factor. KVA is the vector sum of the active power (kW) and the reactive power (kVAR) flowing in a circuit.

kVAR (kilo–Volt–Amperes Reactive)

KVAR is the product of the voltage and the amperage required to excite inductive circuits. It is associated with the reactive power which flows between paralleled generator windings and between generators and load windings that supply the magnetizing currents necessary in the operation of transformers, motors, and other electromagnetic loads. Reactive power does not load the generator set's engine but does limit the generator thermally.

kW (kilo-Watt)

KW is a term used for power rating electrical devices and equipment. Generator sets in the United States are usually rated in kW. KW, sometimes called active power, loads the generator set's engine.

kW Load Alarm

This alarm monitors the kilowatt output at some point in a system and initiates an alarm when the output exceeds a preset amount.

KW Load Sensor

The kW load sensor is an electronic device provided to sense kW level at various points in a system, for use in control functions within the system, such as kW Load Alarms, or load demand.

LAN

Local Area Network

Lead Unit

In a paralleling system that has a load demand feature, the lead unit is the last unit to be shut down in the event that load demand mode is in operation.

Leg

A leg is a phase winding of a generator, or a phase conductor of a distribution system.

Legally Required (Power System)

Equipment and systems that are required to be installed in facilities by law in order to maintain the safety of facility inhabitants (USA code terminology).

Line Voltage

In the context of this manual, line voltage refers to AC operating voltages from 120 to 600 VAC.

Load Demand

Load demand is a paralleling system operating mode in which the system monitors the total kW output of the generator sets, and controls the number of operating sets as a function of the total load on the system. The purpose of load demand controls is to reduce fuel consumption and limit problems caused by light load operation of reciprocating diesel generator sets.

Load Management

Load management is the overall control of load connected to match available generator capacity. Priority control and load shedding are the two features required for load management.

Load Shedding

Load shedding is the process by which the total load on a paralleling system is reduced, on overload of the system bus, so that the most critical loads continue to be provided with reliable electrical service.

Low Voltage

In the context of this manual, low voltage refers to AC system operating voltages from 120 to 600 VAC.

Main Breaker

A main breaker is a circuit breaker at the input or output of the bus, through which all of the bus power must flow. The generator main breaker is the device that can be used to interrupt generator set power output.

Main-Tie-Main (Paralleling System)

A main-tie-main paralleling system is a paralleling system which has two utility feeds separated by a circuit breaker known as a tie breaker. Under normal circumstances the tie breaker remains open and each utility feed is servicing separate loads.

Mains

Mains is a term used extensively outside the United States to describe the normal power service (utility).

Master Control

A control section in a typical paralleling system that provides total system metering and the interface point between the paralleling system and the facility.

Medium Voltage

In the context of this manual, medium voltage refers to AC system operating voltages from 601 to 15,000 VAC.

Molded Case Circuit Breaker

A molded case circuit breaker automatically interrupts the current flowing through it when the current exceeds a certain level for a specified time. *Molded case* refers to the use of molded plastic as the medium of electrical insulation for enclosing the mechanisms and for separating conducting surfaces from one another and from grounded (earthed) metal parts.

NEC (National Electrical Code)

This document is the most commonly referenced general electrical standard in the United States. The NEC was developed by NFPA and is known as NFPA 70.

NEMA

National Electrical Manufacturers Association

NEMA 1 Enclosure

This enclosure designation is for indoor use only-where dirt, dust, and water are not a consideration. Personnel protection is the primary purpose of this type of enclosure.

Neutral

Neutral refers to the common point of a Y–connected AC generator, a conductor connected to that point or to the mid–winding point of a single–phase AC generator.

Neutral Current

Neutral current is the current that flows in the neutral leg of a paralleling system. Often, this term is used in reference to circulating neutral currents or cross currents.

NFPA

National Fire Protection Association

Nonlinear Load

A nonlinear load is a load for which the relationship between voltage and current is not a linear function. Some common nonlinear loads are fluorescent lighting, SCR motor starters, and UPS systems. Nonlinear loads cause abnormal conductor heating and voltage distortion.

Normal Standby Mode

In the normal standby mode, power to the load is supplied by the utility. The paralleling system is ready to provide power to the load in the event of utility failure.

On-Set Paralleling

On-set paralleling is a manual paralleling system that is built onto the generator set, no additional switchboards are required.

One–Line Diagram

A one–line diagram is a schematic diagram of a three–phase power distribution system which uses one line to show all three phases. It is understood when using this easy to read drawing that one line represents three.

Operating Source

An operating source is a source of electrical power that is delivering power to a load. The operating source can be either a generator set or a commercial (utility bus) power line.

OSPS

OSPS is a Cummins Power Generation model designation for traditional paralleling switchgear that incorporates paralleling and master/totalizing controls, with drawout breakers below the controls and the bus structure isolated to the rear of the equipment.

Overcrank

Overcrank is an alarm function provided with most generator sets that indicates that the generator set has failed to start.

Overlapping Neutral

Overlapping neutral is a feature of some 4-pole (switched neutral) transfer switches in which all the neutral contacts of the switch remain closed during the time that the phase conductors are operating. Because of potential operating problems caused by interconnecting the normal and emergency system grounding points, Cummins Power Generation recommends that this operating system should not be used.

Parallel Operation

Parallel Operation is the operation of two or more sources of AC electrical power whose output leads are connected to a common load. Connection of the power sources is made so that the sources electrically function as a single source of power. Parallel Operation requires that the two sources of electrical power must match in voltage, frequency, and number of phases.

Paralleling Breaker

A paralleling breaker is the circuit breaker that connects the generator set to the emergency bus, and across which all the individual generator synchronizing functions occur.

Paralleling Control

A paralleling control contains the electrical equipment provided in a paralleling system for control of a single generator set.

Paralleling Suppressers

Paralleling suppressers are semiconductor devices that protect the silicon diodes on a brushless excitation system from damaging overvoltages. Overvoltages, usually of short duration, occur when a generator is paralleled out of phase with the energized bus.

Peak Shaving

Peak shaving is the process by which loads in a facility are reduced for a short time to limit maximum electrical demand in a facility and to avoid a portion of the demand charges from the local utility.

Permissive Paralleling

Permissive paralleling is a feature in Cummins Power Generation manual and automatic paralleling switchboards that prevents out-of-phase manual paralleling. A synchronizing check relay prevents the electrical closing of the electrically operated circuit breaker if the incoming set is outside of the frequency or phase angle limits required for proper paralleling to a bus.

Phase Rotation

Phase rotation (or phase sequence) describes the order (A–B–C, R–S–T or U–V–W) of the phase voltages at the output terminals of a three–phase generator. The phase rotation of a generator set must match the phase rotation of the normal power source for the facility and must be checked prior to operation of the electrical loads in the facility.

Pitch

Pitch is the ratio of the number of generator stator winding slots enclosed by each coil to the number of winding slots per pole. It is a mechanical design characteristic the generator designer may use to optimize generator cost verse voltage wave form quality.

Plinth

A frame or concrete sub-base used beneath equipment to provide a level of protection from moisture.

Power Circuit Breaker

A power circuit breaker is a circuit breaker whose contacts are forced closed via a spring–charged, over–center mechanism to achieve fast closing (5–cycle) and high withstand and interrupting ratings. A power circuit breaker can be an insulated case or power air circuit breaker.

Power Factor (PF)

The inductances and capacitances in AC circuits cause the point at which the voltage wave passes through zero to differ from the point at which the current wave passes through zero. When the current wave precedes the voltage wave, a leading power factor results, as in the case of capacitive loads or overexcited synchronous motors. When the voltage wave precedes the current wave, a lagging power factor results. This is generally the case. The power factor expresses the extent to which the voltage zero differs from the current zero. Considering one full cycle to be 360 degrees, the difference between the zero points can then be expressed as an angle. Power factor is calculated as the cosine of the angle between zero points and is expressed as a decimal fraction (.8) or as a percentage (80%). It is the ratio of kW and kVA. In other words kW = kVA x PF.

Power Transfer Control

Control system to operate a breaker pair in the same way as a transfer switch.

Prime Power

Prime power describes an application where the generator set (or sets) must supply power on a continuous basis and for long periods of time between shutdowns. No utility service is present in typical prime power applications.

Priority Control

Priority control is the process by which the total load on the bus is limited to the most critical loads in the system until adequate generation capacity is available to serve all loads.

PVC

Polyvinyl Chloride

Pulse Alarm

Pulse alarm is an alarm logic system that allows all alarms to be annunciated, even if a previous alarm has been silenced but is still present in the system.

Random Access Paralleling

Random access paralleling is a paralleling operation where any generator may be the first unit to close to the bus on startup of the system. Random access systems use active synchronizing to force the second and all subsequent generator sets to close to the bus as fast as possible.

Reactance

Reactance is the opposition to the flow of current in AC circuits caused by inductances and capacitances. It is expressed in terms of ohms and its symbol is X.

Reactive Differential Compensation

Reactive differential compensation (also called cross current compensation)is a method of controlling the reactive power supplied by generators in a paralleling system so that they equally share the total reactive load on the bus, without inducing significant voltage droop in the system.

Reactive Droop Compensation

Reactive droop compensation is one method used in paralleled generator sets to enable them to share reactive power supplied to a load. This system causes a drop in the internal voltage of a set when reactive currents flow from that generator. Typically, at full load, 0.8 PF, the output voltage of a set is reduced by 4% from that at no load when reactive droop compensation is used.

Reactive Power

Reactive power is the product of current, voltage and the sine of the angle by which current leads or lags voltage and is expressed as VAR (volts–amperes–reactive).

Reactor

A reactor is an electrical device that applies only reactive load to a system.

Redundant/Parallel Configuration

A redundant/parallel configuration is a paralleling system that is designed with extra generator sets in the system, so that the failure of one (or more) of the generator sets will not require load shedding.

Reverse Power Relay

A reverse power relay is a relay with a wattmeter movement that senses the direction of power flow. In paralleled sets, a flow of reverse power (i.e., power flow into a set) will actuate the reverse power relay and disconnect the set from the system. If one set stops and reverse power protection is not provided, the set still running will drive the set that has stopped. (The generator on the set that has stopped will act as a motor.)

Risers

Risers are rectangular copper or aluminum bars that connect circuit breakers, fusible switches, and transfer switches with the main system bus. As with bus bars, they are sized and assembled in multiples according to the current that they must carry.

Selective Coordination

Selective coordination is the selective application of overcurrent devices such that short circuit faults are cleared by the device immediately on the line side of the fault, and only by that device.

Separately Derived

A separately derived on-site power system has no direct neutral connection with the neutral of the normal electrical service.

Sequential Paralleling

Sequential paralleling is a type of automatic paralleling system where the generators in a system close to the bus in a prescribed order, typically by use of a single synchronizer.

Service Entrance

The service entrance is the point where the utility service enters the facility. In low voltage systems the neutral is grounded at the service entrance.

Shunt Trip

Shunt trip is a feature added to a circuit breaker or fusible switch to permit the remote opening of the breaker or switch by an electrical signal.

Soft Closed Transition

A soft closed transition is a transfer of power from one source to another during which there is a period of time when both sources are simultaneously connected to the load and the load ramps from one source to the other over a period of several seconds. Also called ramping closed transition.

SPF

SPF is a Cummins Power Generation model designation for an automatic exciter paralleling system.

SSPS

SSPS is a Cummins Power Generation model designation for a compact, random access paralleling system.

Standby System

A standby system is an independent power system that allows operation of a facility in the event of normal power failure.

Steady State Rating

Steady state rating is the maximum load that a generator set or paralleling system can carry, on a continuous basis, for the duration of a utility power outage.

Surge Rating

Surge rating is the rating of a machine, usually in excess of its normal operating level, for which it can provide power for a very short time.

Switchboard

Refers to an assembly of equipment including a metal structure, switching devices such as circuit breakers, protective devices, controls and metering. Switchboards in North America are listed to UL 891. Key characteristics of UL 891 Listed switchboards are that they are not braced for short circuits of a duration longer than 3 electrical cycles and they use molded case circuit breakers listed to UL 489. In this document the term “switchboard” is used to generally apply to both switchboards and switchgear due to confusion that might occur due to differences in the use of the term “switchgear” in some global marketplaces. IEC 61439 is the governing standard for switchboards and switchgear in IEC markets.

Switchgear

Refers to an assembly of equipment including a metal structure, switching devices such as circuit breakers, protective devices, controls and metering that is assembled in compliance to ANSI standards. Switchgear in North America may be UL 1558 listed and labeled. Key characteristics of UL 1558 Listed switchgear are that it is braced for extended duration short circuits and uses power circuit breakers listed to UL 1066. In this document the term “switchboard” is used to generally apply to both switchboards and switchgear due to confusion that might occur due to differences in the use of the term “switchgear” in some global marketplaces. IEC 61439 is the governing standard for switchboards and switchgear in IEC markets.

Sync Check Relay

A sync check relay is an electrical device that monitors the phase relationship between two voltage sources and provides a signal when the voltage sources are within specific preset parameters.

Synchronization

In a paralleling application, synchronization is obtained when an incoming generator set is matched with and in step to the same frequency, voltage, and phase sequence as the operating power source.

Synchronizer

A Synchronizer is an electronic device that monitors the phase relationship between two voltage sources and provides a correction signal to an engine governor, to force the generator set to synchronize with a system bus.

Synchronizing Lights

Synchronizing Lights are lamps connected across the line contactor of the incoming generator set. The lights indicate when the voltage waveforms of the incoming and operating power sources coincide and paralleling can be completed.

Synchroscope

A synchroscope is a meter that indicates the relative phase angle between an incoming set voltage and the bus voltage. The synchroscope pointer indicates whether the set is faster or slower than the bus and allows the operator to adjust the frequency (speed) accordingly before manually paralleling to the bus.

Total Harmonic Distortion (THD)

See Harmonic Distortion

Totalizer/Totalizing Control

See Master Control.

TPC

Transfer Pair Control

Transfer Pair (Paralleling System)

A paralleling system topology in which two electrically operated circuit breakers are controlled to connect two power sources to a common load.

Transfer Switch

A transfer switch is an electrical device for switching loads between alternate power sources. An automatic transfer switch monitors the condition of the sources and connects the load to the alternate source if the preferred source fails.

Type Testing

A test process performed on pre-production prototype equipment to validate the performance of the equipment. Also termed "prototype testing".

UL

Underwriters Laboratories

Utility

The utility is a commercial power source that supplies electrical power to specific facilities from a large central power plant.

Utility Bus Main Breaker

An electrically operated circuit breaker whose primary purpose is to connect a utility bus to loads.

Voltage Control

The Voltage Control is a rheostat that sets the operating point of the voltage regulator and therefore controls the output voltage of the generator set, within its design limits.

Watthour Demand Meter

A watthour demand meter is similar to a watthour meter except that it also provides an indication of the highest kW load level achieved during operation.

Watthour Meter

A watthour meter records the total power output at a specific point in a system. Typical recording increment is in kW-hours.

Wattmeter

A wattmeter records power being delivered from a source to the load. Wattmeters for paralleling systems are calibrated in kilowatts.

8.8 Acronyms

Acronym	Description
A/D	Analog to Digital
AC	Alternating Current
ACB	Air Circuit Breaker
ANSI	American National Standards Institute
AS, or AUS	Australia
ASME	American Society of Mechanical Engineers
ASTM	American Society of Testing and Materials
ATS	Automatic Transfer Switch
AVR	Automatic Voltage Regulator
AWG	American Wire Gauge
BACnet	Building Automation and Control Networks
BIL	Basic Impulse Level
CAN	Controlled Area Network
CB	Circuit Breaker
CCC	Certification agency of the Peoples Republic of China
CCM	Controls Communication Module
CE	Conformite Europeenne
CGT	Cummins Generator Technologies
CSA	Canadian Standards Association
CSV	Comma Separated Value
CT	Current Transformer
dB	Decibel
DC	Direct Current
DHCP	Dynamic Host Configuration Protocol
DIM	Digital Input/Output Module
DMC	Digital Master Control
DNS	Domain Name System
E-Stop	Emergency Stop
ECM	Engine Control Module (control for emissions-compliant engines)
ECS	Engine Control System
EMI	Electromagnetic Interference
EIA/TIA	Electronic Industry Association/Telecommunications Industry Association
EN	European Standard
EPS	Engine Protection System
FAE	Full Authority Electronic (Engine or Control)
FMEA	Failure Mode Effect Analysis

Acronym	Description
FMI	Failure Mode Identifier
FSO	Fuel Shut Off
GB	Gigabyte
GCS	Generator Control System
GEN	Alternator/Generator
Genset	Generator Set
GFCI	Ground Fault Circuit Interrupter (North America)
GND	Ground (Earth)
GOOSE	Generic Object Oriented Substation Events
GOV	Governor
HMI	Human Machine Interface (Operator Panel)
I/E	Import/Export Control
IC	Integrated Circuit
IEEE	Institute of Electrical and Electronics Engineers
ILS	Isochronous Load Sharing Control
IP	Ingress Protection (primarily used in IEC markets)
ISO	International Standards Organization
kVA	Kilovolt-amps (a measure of load power consumption or alternator capacity)
kVAR	Kilovar (a measure of reactive power)
kW	Kilowatt (a measure of real power)
LAN	Local Area Network
LCD	Liquid Crystal Display
LCL	Low Coolant Level
LED	Light Emitting Diode
LLC	Logical Link Control
LNS	LonWorks Network Services
LSIG	Long, Short, Instantaneous, Ground Fault (reference to CB trip unit)
MAC	Media Access Control
MB	Megabyte
Mil Std	Military Standard (USA)
NC	Normally closed; or, Not Connected
NEC	National Electrical Code (NFPA 70, the US National Electrical Code)
NEMA	National Electrical Manufacturer’s Association (Primarily in N America)
NFPA	National Fire Protection Association
NO	Normally Open
NWF	Network Failure
NZ	New Zealand
OEM	Original Equipment Manufacturer

Acronym	Description
OOR	Out of Range
OORH, or ORH	Out of Range High
OORL, or ORL	Out of Range Low
OSHA	Occupational Safety and Health Administration (U.S. government entity)
OSI	Open Systems Interconnection
PB	Push button
PC	Personal Computer
PCC	PowerCommand Control (A Cummins control system)
PF	Power Factor
PGI	PowerGen Interface
PGN	Parameter Group Number
PI	Proportional/Integral
PID	Proportional/Integral/Derivative
PLC	Programmable Logic Control
PLL	Parallel/Paralleling (usually in reference to a paralleling control)
PMG	Permanent Magnet Generator
PT	Potential Transformer
PTC	Power Transfer Control
PWM	Pulse-Width Modulation
RFI	Radio Frequency Interference (susceptibility or transmission)
RH	Relative Humidity
RMS	Root Mean Square
RTU	Remote Terminal Unit
SAE	Society of Automotive Engineers
SCADA	Supervisory Control and Data Acquisition
SNMP	Simple Network Management Protocol
SPN	Suspect Parameter Number
SW B+	Switched B+ (B+ DC power supply available when engine is running)
SYNC	Synchronizer
T-011	Transfer Switch Application Manual (Cummins)
T-016	Paralleling Application Manual (Cummins)
T-030	Generator Set Application Manual (Cummins)
TCP	Transmission Control Protocol
THD	Total Harmonic Distortion
UL	Underwriters Laboratories
UPS	Uninterruptible Power Supply
UTP	Unshielded Twisted Pair
VT	Voltage Transformer (same function as PT)

Acronym	Description
WAN	Wide Area Network

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