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Exam Preview:

1. In residential and rural areas, the nominal supply is a 120/240 V, single-phase, three-wire grounded system. If three-phase power is required in these areas, the systems are normally 208Y/120 V or less commonly 240/120 V.
   a. True
   b. False
2. Turbine units can be built for almost any desired capacity. Most of the installed steam turbine generators are rated less than ___ MW.
   a. 250
   b. 500
   c. 750
   d. 800
3. Usually, generated power is transformed in a substation, located at the generating station, to 46 kV or more for transmission. Which of the following is NOT defined as a standard nominal transmission system voltage?
   a. 69 kV
   b. 115 kV
   c. 139 kV
   d. 230 kV
4. Aluminum requires smaller conductor sizes to carry the same current as copper. The equivalent aluminum cable, when compared to copper in terms of ampacity, will be lighter in weight and smaller in diameter.
   a. True
   b. False

5. The AWG or conductor sizes are numbered from 30 to 1, then continuing with 0, 00, 000, and 0000 (or 1/0, 2/0, 3/0, and 4/0 respectively). Number 30 is the smallest size and ___ the largest in this system.
    a. 1/00
    b. 2/0
    c. 3/0
    d. 4/0
6. Lead or lead alloys are used for industrial power cable sheaths for maximum cable protection in underground manhole and tunnel or underground duct distribution systems subject to flooding.
    a. True
    b. False
7. Normal loading limits of insulated wire and cable are determined based on many years of practical experience. The anticipated rate of deterioration equates to a useful life of approximately _______ years.
    a. 40 to 60
    b. 5 to 15
    c. 20 to 30
    d. 50 to 80
8. Power equipment is normally rated according to the nominal system voltage. In equipment terminology, the voltage ratings fall into four classes. Which of the voltage ranges is classified as “High Voltage”?
    a. above 242,000 V to 800,000 V
    b. above 600 V to 72,500 V
    c. 600 V or less.
    d. above 72,500 V to 242,000 V
9. Low cost, high dielectric strength, and ability to recover after dielectric overstress make mineral oil the most widely used transformer insulating material. Due to its flammable property, oil-insulated transformers are normally used for outdoor installations. Indoor installations require vaults and venting or fire suppression systems.
    a. True
    b. False
10. Standard 3-phase two-winding power transformers are connected in various configurations. Which of the following connections matches the description: these connections are seldom used since they are subject to disturbances from harmonic voltages and currents?
    a. Wye-Delta
    b. Delta-Delta
    c. Wye-Wye
    d. Open-Delta

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CHAPTER 1. PRINCIPLES OF POWER SYSTEMS.

1.1 TYPICAL POWER NETWORK. An understanding of basic design principles is essential in the operation of electric power systems. This chapter briefly describes and defines electric power generation, transmission, and distribution systems (primary and secondary). A discussion of emergency and standby power systems is also presented. Figure 1-1 shows a one-line diagram of a typical electrical power generation, transmission, and distribution system.

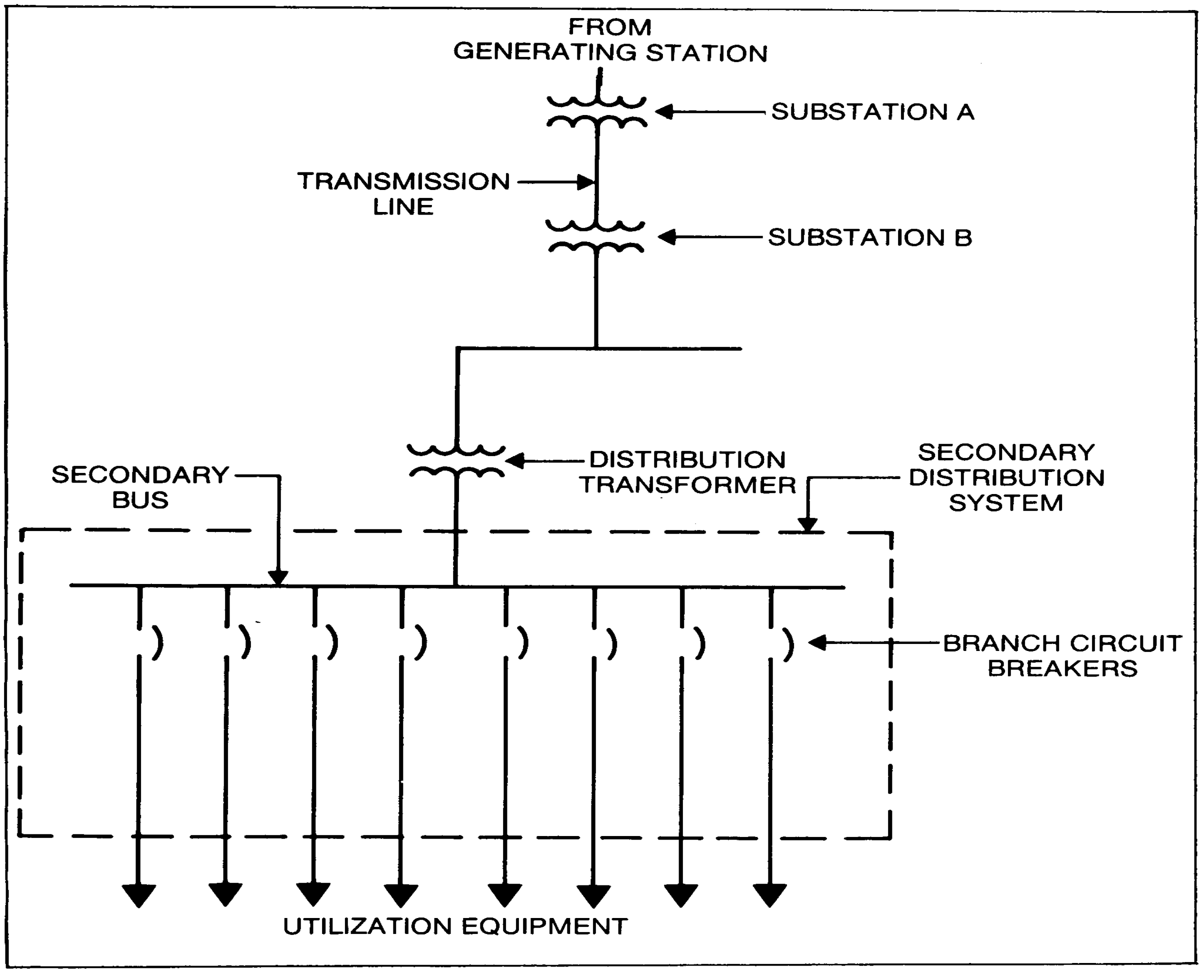


FIGURE 1-1
Typical Electric Power Generation,
Transmission, and Distribution System

1.2 ELECTRIC POWER GENERATION. A generator is a machine that transforms mechanical energy into electric power. Prime movers such as engines and turbines convert thermal or hydraulic energy into mechanical power. Thermal energy is derived from the fission of nuclear fuel or the burning of common fuels such as oil, gas, or coal. The alternating current generating units of electric power utilities generally consist of steam turbine generators, gas combustion turbine generators, hydro (water) generators, and internal-combustion engine generators.

1.2.1 Prime Movers. The prime movers used for utility power generation are predominantly steam turbines and internal-combustion machines. High-pressure/high-temperature and high-speed (1800 to 3600 rotational speed (rpm)) steam turbines are used primarily in large industrial and utility power generating stations. Internal-combustion machines are normally of the reciprocating-engine type. The diesel engine is the most commonly used internal-combustion machine, although some gasoline engines are also used.

1.2.2 Generators.

1.2.2.1 Generator Capacity. Turbine units can be built for almost any desired capacity. The capacity of steam turbine driven generators in utility plants range from 5 MW to 1000 MW. Most of the installed steam turbine generators are rated less than 500 MW. Gas turbine generators for electric power generation generally have capacities ranging from 100 kW to 20 MW (but are used in multiple installations). The applications of gas turbine generators include both continuous and peak load service. Diesel engine generator sets have capacities ranging from 500 kW to 6500 kW. These units are widely used in auxiliary or standby service in portable or stationary installations, but they may be used as the primary power source in some locations. Smaller units (steam turbine, gasoline, or diesel engine) are also available for special applications or industrial plants. See NAVFAC MO-322 for testing procedures.

1.2.2.2 Generator Voltage. Large generators used by commercial utilities are usually designed with output voltages rated between 11 and 18 kV. Industrial plant generators are normally rated 2.4 kV to 13.8 kV, coinciding with standard distribution voltages. The generated voltage is stepped up to higher levels for long distance power transmission.

1.2.2.3 Generator Frequency. Power generation in the United States is standardized at 60 Hz. The standard frequency is 50 Hz in most foreign countries. Generators operating at higher frequencies are available for special applications.

1.2.3 Voltage and Frequency Controls.

1.2.3.1 Voltage Control. The terminal voltage of a generator operating in isolation is a function of the excitation on the rotor field winding. The generator output terminal voltage is normally maintained at the correct level by an automatic voltage regulator that adjusts the field current.

1.2.3.2 Frequency Control. Electrical frequency is directly proportional to the rpm of the rotor which is driven by the prime mover. Because of this relationship, prime movers are controlled by governors that respond to variation in speed or frequency. The governor is connected to the throttle control mechanism to regulate speed, accomplishing frequency control automatically.

1.2.4 Parallel Operation of Generators. Large power plants normally have more than one generator in operation at the same time. When generators are to be paralleled, it is necessary to synchronize the units before closing the paralleling circuit breaker. This means that the generators must be brought to approximately the same speed, the same phase rotation and position, and the same voltage. Proper synchronization is accomplished with the aid of a synchroscope, an instrument which indicates the difference in phase position and in frequency of two sources. Paralleling of generators is accomplished either manually or automatically with one incoming unit at a time.

1.2.5 DC Generation. The requirement for direct current power is limited largely to special loads; for example, electrochemical processes, railway electrification, cranes, automotive equipment, and elevators. Direct current power may be generated directly as such, but is more commonly obtained by conversion or rectification of AC power near the load.

1.3 ALTERNATING CURRENT POWER TRANSMISSION SYSTEM. The transmission system is the bulk power transfer system between the power generation station and the distribution center from which power is carried to customer delivery points. The transmission system includes step-up and step-down transformers at the generating and distribution stations, respectively. The transmission system is usually part of the electric utility's network. Power transmission systems may include subtransmission stages to supply intermediate voltage levels. Subtransmission stages are used to enable a more practical or economical transition between transmission and distribution systems.

1.3.1 Transmission Voltage. Usually, generated power is transformed in a substation, located at the generating station, to 46 kV or more for transmission. Standard nominal transmission system voltages are: 69 kV, 115 kV, 138 kV, 161 kV and 230 kV. Some transmission voltages, however, may be at 23 kV to 69 kV, levels normally categorized as primary distribution system voltages. There are also a few transmission networks operating in the extra-high-voltage class (345 kV to 765 kV).

1.3.2 Transmission Lines. Transmission lines supply distribution substations equipped with transformers which step the high voltages down to lower levels. The transmission of large quantities of power over long distances is more economical at higher voltages. Power transmission at high voltage can be accomplished with lower currents which lower the I^2R (Power) losses and reduce the voltage drop. The consequent use of smaller conductors requires a lower investment. Standard power transmission systems are 3-phase, 3-conductor, overhead lines with or without a ground conductor. Transmission lines are classed as unregulated because the voltage at the generating station is controlled only to keep the lines operating within normal voltage limits and to facilitate power flow.

1.4 PRIMARY DISTRIBUTION SYSTEMS. The transmission system voltage is stepped-down to lower levels by distribution substation transformers. The primary distribution system is that portion of the power network between the distribution substation and the utilization transformers. The primary distribution system consists of circuits, referred to as primary or distribution feeders, that originate at the secondary bus of the distribution substation. The distribution substation is usually the delivery point of electric power in large industrial or commercial applications.

1.4.1 Nominal System Voltages. Primary distribution system voltages range from 2,400 V to 69,000 V. Some of the standard nominal system voltages are:

Volts	Phase	Wire
4,160Y/2,400	Three	Four
4,160	Three	Three
6,900	Three	Three
12,470Y/7,200	Three	Four
12,470	Three	Three
13,200Y/7,620	Three	Four
13,200	Three	Three
13,800Y/7,970	Three	Four
13,800	Three	Three
24,940Y/14,400	Three	Four
34,500	Three	Three
69,000	Three	Three

The primary distribution voltages in widest use are 12,470 V and 13,200 V, both three wire and four wire. Major expansion of distribution systems below the 15 kV nominal level (12 kV - 14.4

kV) is not recommended due to the increased line energy costs inherent with lower voltage systems.

1.4.2 Distribution Substations. A substation consists of one or more power transformer banks together with the necessary voltage regulating equipment, buses, and switchgear.

1.4.2.1 Substation Arrangements. A simple substation arrangement consists of one incoming line and one transformer. More complicated substation arrangements result when there are two or more incoming lines, two or more power transformers, or a complex bus network.

Some typical distribution substation arrangements are shown in Figure 1-2. Specific sections are identified as follows:

(a) A primary section provides for the connection of one or more incoming high-voltage circuits. Each circuit is provided with a switching device or a combination switching and interrupting device.

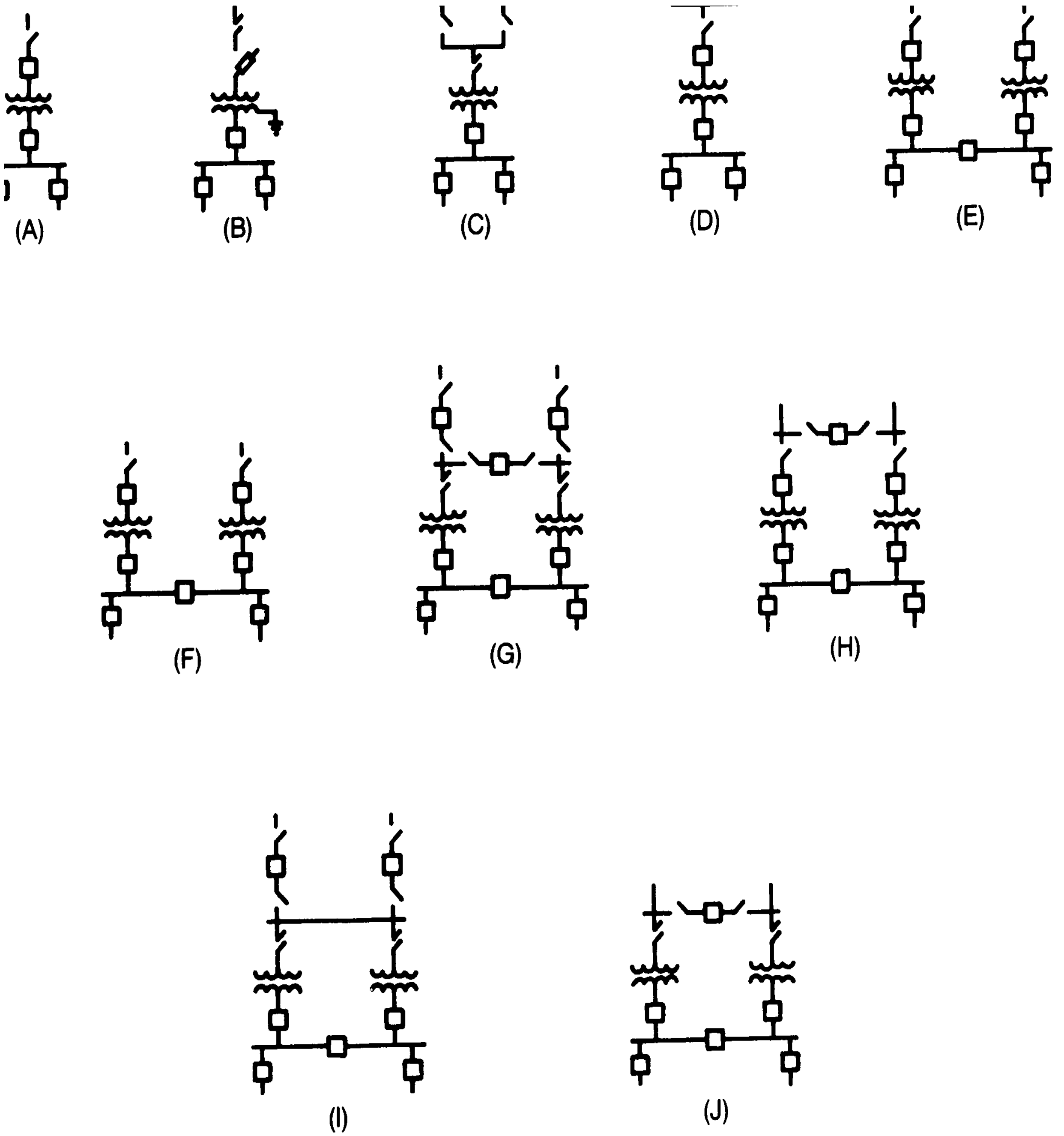


FIGURE 1-2
Typical Distribution Substation Arrangements

(b) A transformer section includes one or more transformers with or without automatic load-tap-changing (voltage regulating) capability.

(c) A secondary section provides for the connection of one or more secondary feeders. Each feeder is provided with a switching and interrupting device.

1.4.2.2 Substation Bus Arrangements. A bus is a junction of two or more incoming and outgoing circuits. The most common bus arrangement consists of one source or supply circuit and one or more feeder circuits. The numerous other arrangements and variations are mainly intended to improve the service reliability through the bus to all or part of the load during scheduled maintenance or unexpected power outages. Typical bus arrangements are shown in Figure 1-3.

The arrangements are normally referred to as:

(a) Double-bus.
(b) Two-source sectionalizing bus.
(c) Three-source sectionalizing bus.
(d) Star or synchronizing bus.

When two sources are used simultaneously, but must not be operated in parallel, a normally open bus-tie circuit breaker is interlocked with the source circuit breakers. This permits serving both bus sections from one of the sources when the other is not available. For normally parallel sources, a single straight bus may be used. It is preferable, however, to use a normally closed bus-tie circuit breaker to split the system so that service continuity can be retained on either section when the other section is out of service.

1.4.2.3 Substation Operation. Substations may be attended by operators or designed for automatic or remote control of the switching and voltage regulating equipment. Most large new substations are either automatic or remotely controlled.

(a) In an automatic substation, switching operations are controlled by a separately installed control system. Major apparatus, such as transformers and converting equipment, may be placed in or taken out of service automatically. Feeder circuit breakers, after being opened, can be reclosed by protective relays or by the control system.

(b) Remote control substations are often within a suitable distance from attended stations. In such cases pilot-wire cables provide the communication link to receive indications of circuit breaker or switch positions and to transmit control adjustments, as required. Microwave radio, telephone lines, and carrier current are often used for remote-control links at distances beyond the economic reach of pilot wire systems.

1.4.3 <u>Types of Systems</u>. There are two fundamental types of primary distribution systems; radial and network. Simply defined, a radial system has a single simultaneous path of power flow to the load. A network has more than one simultaneous path. Each of the two types of systems has a number of variations. Figure 1-4 illustrates four primary feeder arrangements showing tie, loop, radial and parallel feeders. There are other more complex systems, such as the primary network (interconnected substations with feeders forming a grid) and dual-service network (alternate feeder to each load). These systems, however, are simply variations of the two basic feeder arrangements.

The following paragraphs discuss the functions and characteristics of the simpler feeder arrangements.

1.4.3.1 Tie Feeder. The main function of a tie feeder is to connect two sources. It may connect two substation buses in parallel to provide service continuity for the load supplied from each bus.

1.4.3.2 Loop Feeder. A loop feeder has its ends connected to a source (usually a single source), but its main function is to supply two or more load points in between. Each load point can be supplied from either direction; so it is possible to remove any section of the loop from service without causing an outage at other load points. The loop can be operated normally closed or normally open. Most loop systems are, however, operated normally open at some point by means of a switch. The operation is very similar to that of two radial feeders.

1.4.3.3 Radial Feeder. A radial feeder connects between a source and a load point, and it may supply one or more additional load points between the two. Each load point can be supplied from one direction only. Radial feeders are most widely used by the Navy because the circuits are simple, easy to protect, and low in cost.

1.4.3.4 Parallel Feeder. Parallel feeders connect the source and a load or load center and provide the capability of supplying power to the load through one or any number of the parallel feeders. Parallel feeders provide for maintenance of feeders (without interrupting service to loads) and quick restoration of service when one of the feeders fails.

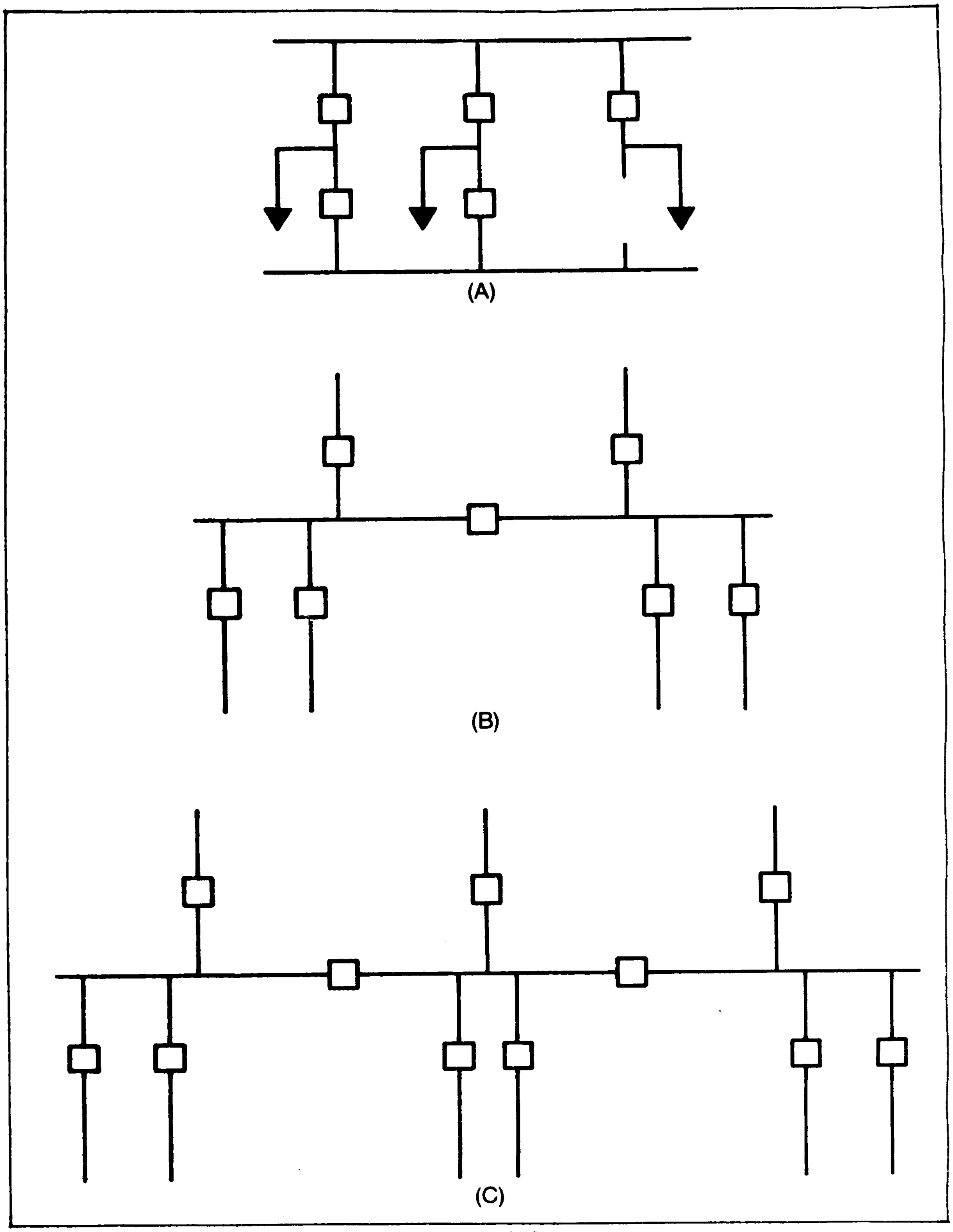


FIGURE 1-3
Typical Bus Arrangements

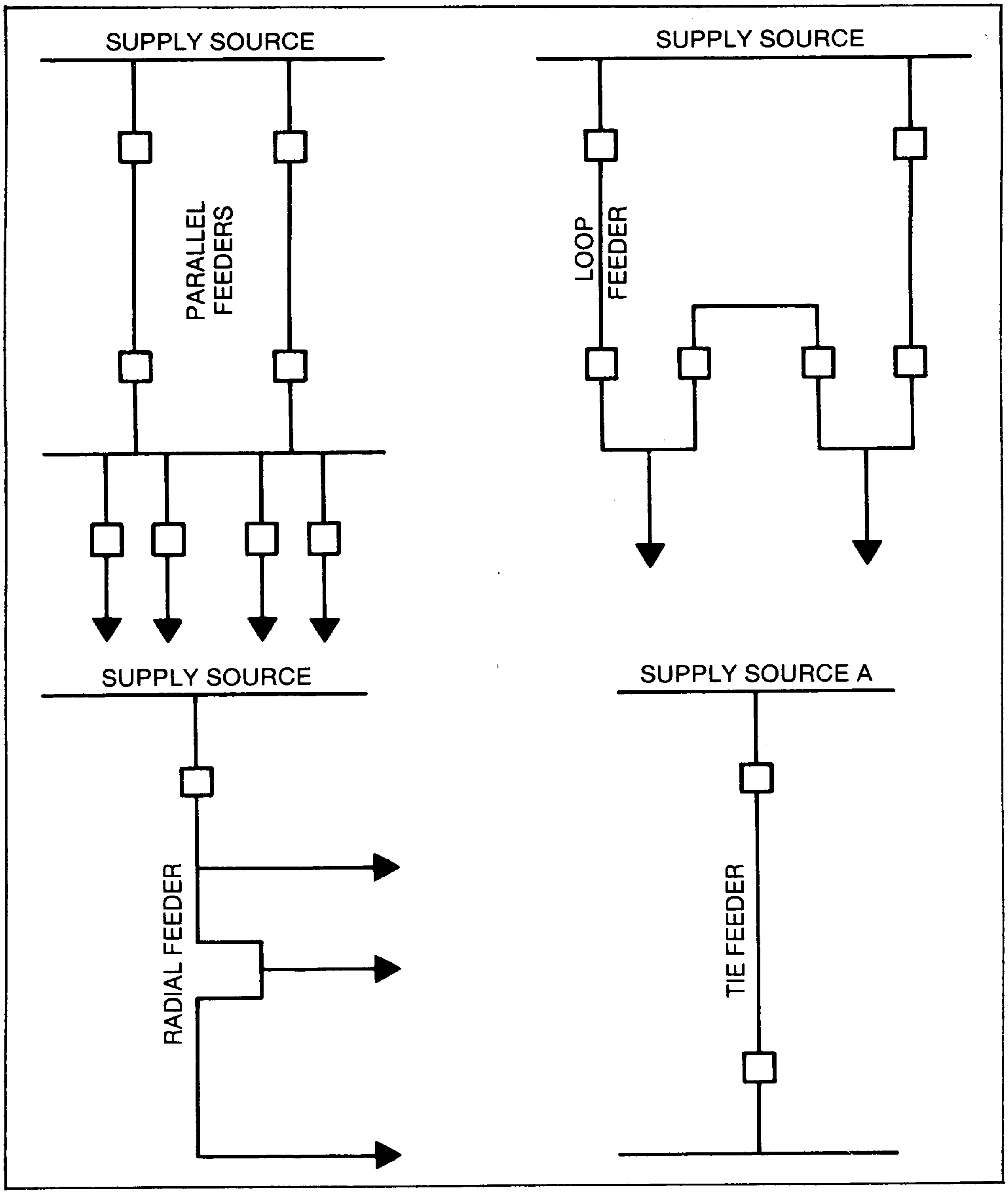


FIGURE 1-4
Four Primary Feeder Arrangements

1.5 SECONDARY DISTRIBUTION SYSTEMS. The secondary distribution system is that portion of the network between the primary feeders and utilization equipment. The secondary system consists of step-down transformers and secondary circuits at utilization voltage levels. Residential secondary systems are predominantly single-phase, but commercial and industrial systems generally use three-phase power.

1.5.1 Secondary Voltage Levels. The voltage levels for a particular secondary system are determined by the loads to be served. The utilization voltages are generally in the range of 120 to 600 V. Standard nominal system voltages are:

Volts	Phase	Wire
120	Single	2
120/240	Single	3
208Y/120	Three	4
240	Three	3
480Y/277	Three	4
480	Three	3
600	Three	3

In residential and rural areas the nominal supply is a 120/240 V, single-phase, three-wire grounded system. If three-phase power is required in these areas, the systems are normally 208Y/120 V or less commonly 240/120 V. In commercial or industrial areas, where motor loads are predominant, the common three-phase system voltages are 208Y/120 V and 480Y/277 V. The preferred utilization voltage for industrial plants, however, is 480Y/277 V. Three-phase power and other 480 V loads are connected directly to the system at 480 V and fluorescent lighting is connected phase to neutral at 277 V. Small dry-type transformers, rated 480-208Y/120 or 480-120/240 V, are used to provide 120 V single-phase for convenience outlets and to provide 208 V single- and three-phase for small tools and other machinery.

1.5.2 Types of Systems. Various circuit arrangements are available for secondary power distribution. The basic circuits are: simple radial system, expanded radial system, primary selective system, primary loop system, secondary selective system, and secondary spot network.

1.5.2.1 Conventional Simple-Radial Distribution System. In the simple-radial system

(Figure 1-5), distribution is at the utilization voltage. A single primary service and distribution transformer supply all the feeders. There is no duplication of equipment. System investment is the lowest of all circuit arrangements. Operation and expansion are simple. Reliability is high if quality components are used, however, loss of a cable, primary supply, or transformer will cut off service. Further, electrical service is interrupted when any piece of service equipment must be deenergized to perform routine maintenance and servicing.

1.5.2.2 Expanded Radial Distribution System. The advantages of the radial system may be applied to larger loads by using a radial primary distribution system to supply a number of unit substations located near the load centers with radial secondary systems (Figure 1-6). The advantages and disadvantages are similar to those described for the simple radial system.

1.5.2.3 Primary Selective Distribution System. Protection against loss of a primary supply can be gained through use of a primary selective system (Figure 1-7). Each unit substation is connected to two separate primary feeders through switching equipment to provide a normal and an alternate source. When the normal source feeder is out of service for maintenance or a fault, the distribution transformer is switched, either manually or automatically, to the alternate source. An interruption will occur until the load is transferred to the alternate source. Cost is somewhat higher than for a radial system because primary cable and switchgear are duplicated.

1.5.2.4 Loop Primary-Radial Distribution System. The loop primary system (Figure 1-8) offers nearly the same advantages and disadvantages as the primary selective system. The failure of the normal source of a primary cable fault can be isolated and service restored by sectionalizing. Finding a cable fault in the loop, however, may be difficult and dangerous. The quickest way to find a fault is to sectionalize the loop and reclose, possibly involving several reclosings at the fault. A section may also be energized at both ends, thus, effecting another potential danger. The cost of the primary loop system may be somewhat less than that of the primary selective system. The savings may not be justified, however, in view of the disadvantages.

1.5.2.5 Secondary Selective-Radial Distribution System. When a pair of unit substations are connected through a normally open secondary tie circuit breaker, the result is a secondary selective-radial distribution system (Figure 1-9). If the primary feeder or a transformer fails, the main secondary circuit breaker on the affected transformer is opened and the tie circuit breaker is closed. Operation may be manual or automatic. Normally, the stations operate as radial systems. Maintenance of primary feeders, transformer, and main secondary circuit breakers is possible with only momentary power interruption, or no interruption, if the stations may be operated in parallel during switching. With the loss of one primary circuit or transformer, the total substation load may be supplied by one transformer. In this situation, however, if load shedding is to be avoided, both transformers and each feeder must be oversized to carry the total load. A distributed secondary selective system has pairs of unit substations in different locations connected by tie cables and normally open tie circuit breakers. The secondary selective system may be combined with the primary selective system to provide a high degree of reliability.

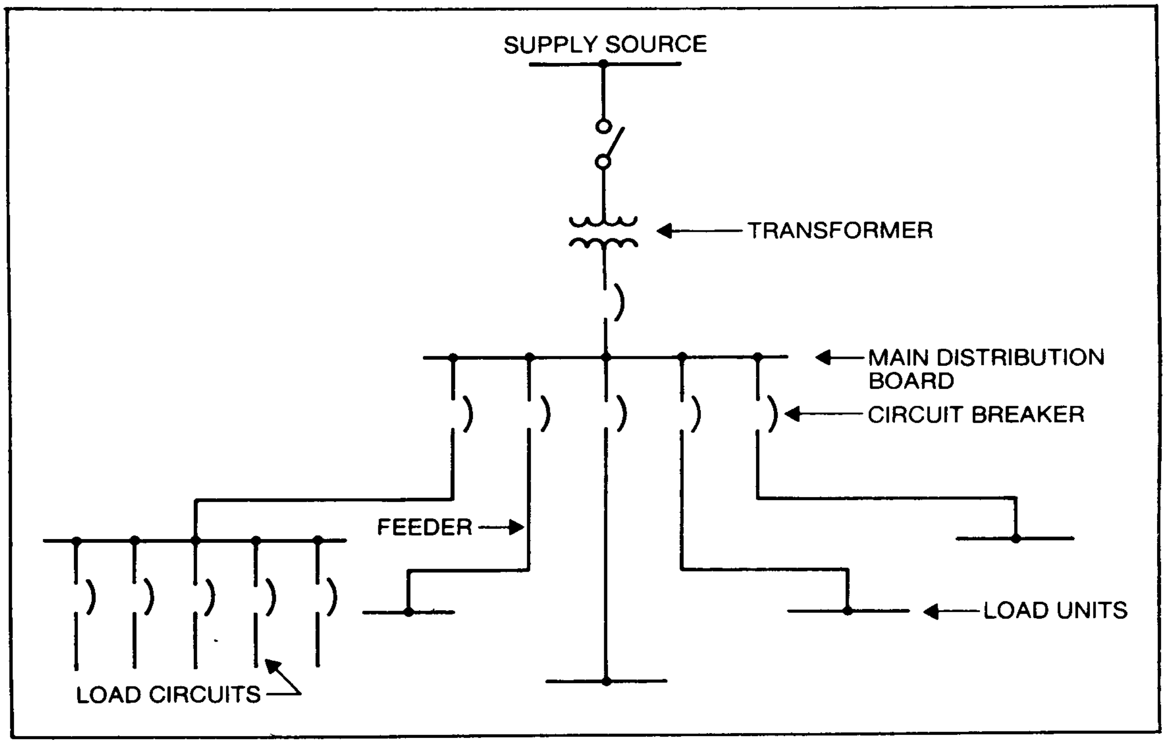


FIGURE 1-5
Conventional Simple-Radial Distribution System

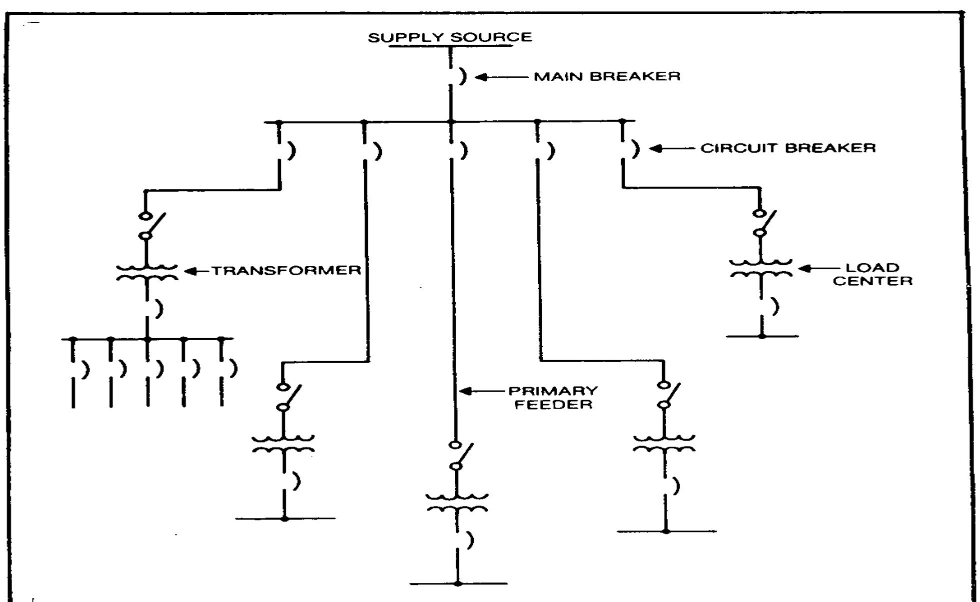


FIGURE 1-6
Expanded Radial Distribution System

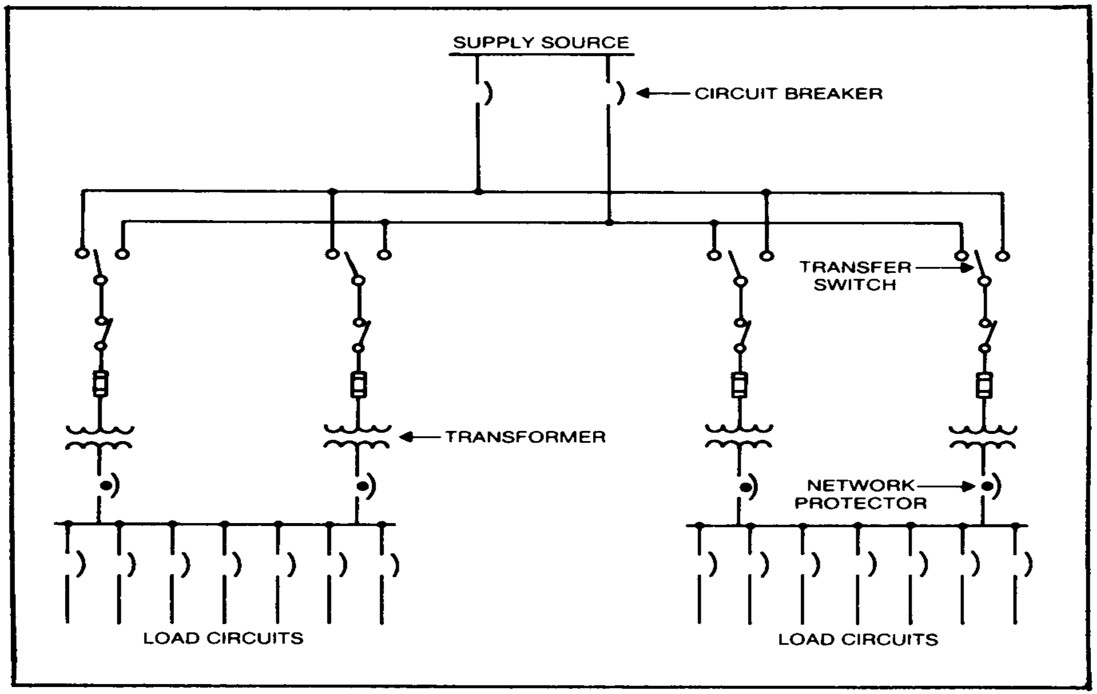


FIGURE 1-7
Primary Selective Distribution System

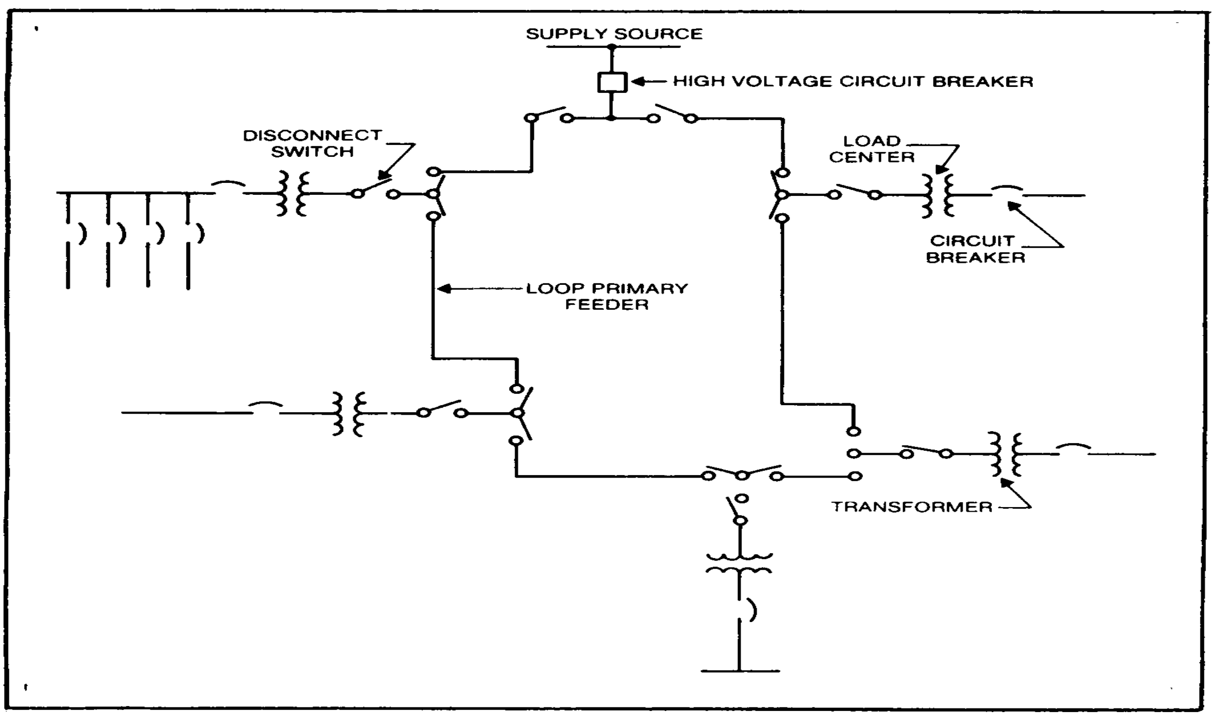


FIGURE 1-8
Loop Primary-Radial Distribution System

1.5.2.6 Secondary Network Distribution System. In a secondary network distribution system, two or more distribution transformers are each supplied from a separate primary distribution feeder (Figure 1-10).

The secondaries of the transformers are connected in parallel through a special type of circuit breaker, called a network protector, to a secondary bus. Radial secondary feeders are tapped from the secondary bus to supply loads. A more complex network is a system in which the low-voltage circuits are interconnected in the form of a grid or mesh.

(a) If a primary feeder fails, or a fault occurs on a primary feeder or distribution transformer, the other transformers start to feed back through the network protector on the faulted circuit. This reverse power causes the network protector to open and disconnect the faulty supply circuit from the secondary bus. The network protector operates so fast that there is minimal exposure of secondary equipment to the associated voltage drop.

(b) The secondary network is the most reliable for large loads. A power interruption can only occur when there is a simultaneous failure of all primary feeders or when a fault occurs on the secondary bus. There are no momentary interruptions as with transfer switches on primary selective, secondary selective, or loop systems. Voltage dips which could be caused by faults on the system, or large transient loads, are materially reduced.

(c) Networks are expensive because of the extra cost of the network protector and excess transformer capacity. In addition, each transformer connected in parallel increases the available short-circuit current and may increase the duty rating requirement of secondary equipment.

1.5.2.7 Secondary Banking. The term banking means to parallel, on the secondary side, a number of transformers. All of the transformers are connected to the same primary feeder. Banking is usually applied to the secondaries of single-phase transformers, and the entire bank must be supplied from the same phase of the primary circuit. All transformers in a bank are usually of the same size and should have the same nominal impedance.

(a) The advantages of banking include: reduction in lamp flicker caused by starting motors, less transformer capacity required because of greater load diversity, and better average voltage along the secondary.

(b) Solid banking, where the secondary conductors are connected without overcurrent protection, is usually not practiced because of the obvious risks. Three methods of protecting banked transformers are shown in Figure 1-11. In each arrangement the transformers are connected to the primary feeder through high-voltage protective links or fuses. Each method has different degrees of protection, depending on the location of the protective devices in the

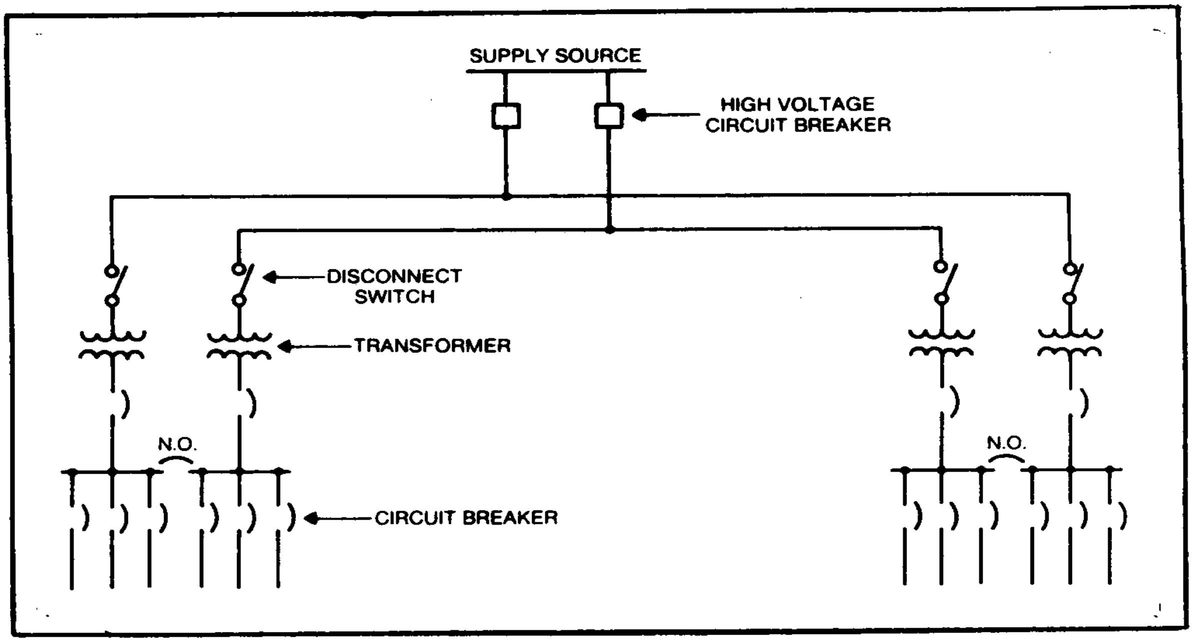


FIGURE 1-9
Secondary Selective-Radial Distribution System

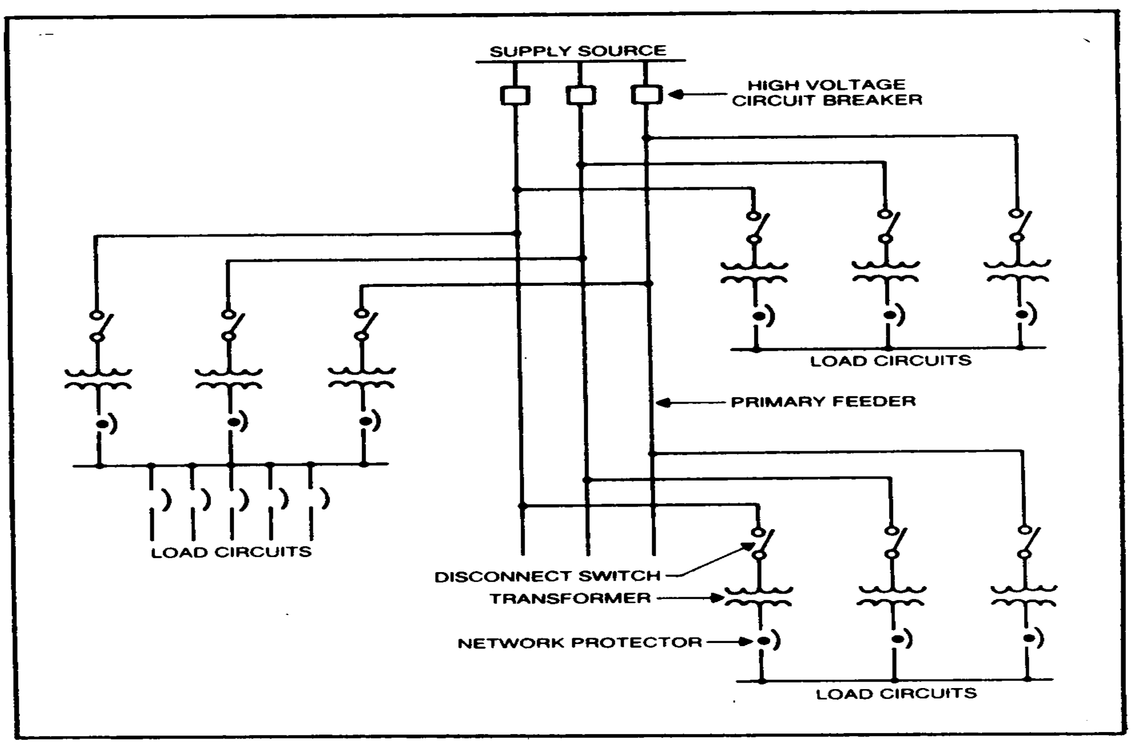


FIGURE 1-10
Secondary Network Distribution System

secondary. Figure 1-11(A) offers the least protection due to the slow acting fuses normally used in this configuration. In the arrangement of Figure 1-11(B), the secondary circuit is sectionalized and the faulted section can be isolated by the fuses.

The third scheme, shown in Figure 1-11(C), utilizes special transformers designed exclusively for banked secondary operation. These transformers, known as completely self-protecting transformers for banking (CSPB), contain in one integral unit the high-voltage protective link and the two secondary breakers. When excessive current flows in one of the breakers, it will trip independently of the other. Fault current protection and sectionalizing of secondary banks are more efficiently accomplished by this method.

1.6 EMERGENCY AND STANDBY POWER SYSTEMS. The principle and practices of emergency and standby power systems is presented in this section. Mobile equipment and uninterruptible power supply (UPS) systems are also discussed. Technical information is included on typical equipment and systems.

1.6.1 Definitions.

1.6.1.1 Emergency Power System. An emergency power system is an independent reserve source of electric energy. Upon failure or outage of the normal or primary power source, the system automatically provides reliable electric power within a specified time. The electric power is provided to critical devices and equipment whose failure to operate satisfactorily would jeopardize the health and safety of personnel or result in damage to property. The emergency power system is usually intended to operate for a period of several hours to a few days. See NAVFAC MO-322 for testing procedures.

1.6.1.2 Standby Power System. An independent reserve source of electric energy which, upon failure or outage of the normal source, provides electric power of acceptable quality and quantity so that the user's facilities may continue satisfactory operation. The standby system is usually intended to operate for periods of a few days to several months, and may augment the primary power source under mobilization conditions.

1.6.1.3 Uninterruptible Power Supply (UPS). UPS is designed to provide continuous power and to prevent the occurrence of transients on the power service to loads which cannot tolerate interruptions and/or transients due to sensitivity or critical operational requirements.

1.6.2 System Description.

1.6.2.1 Emergency Power Systems. Emergency power systems are of two basic types:

(a) An electric power source separate from the prime source of power, operating in parallel, which maintains power to the critical loads should the prime source fail.

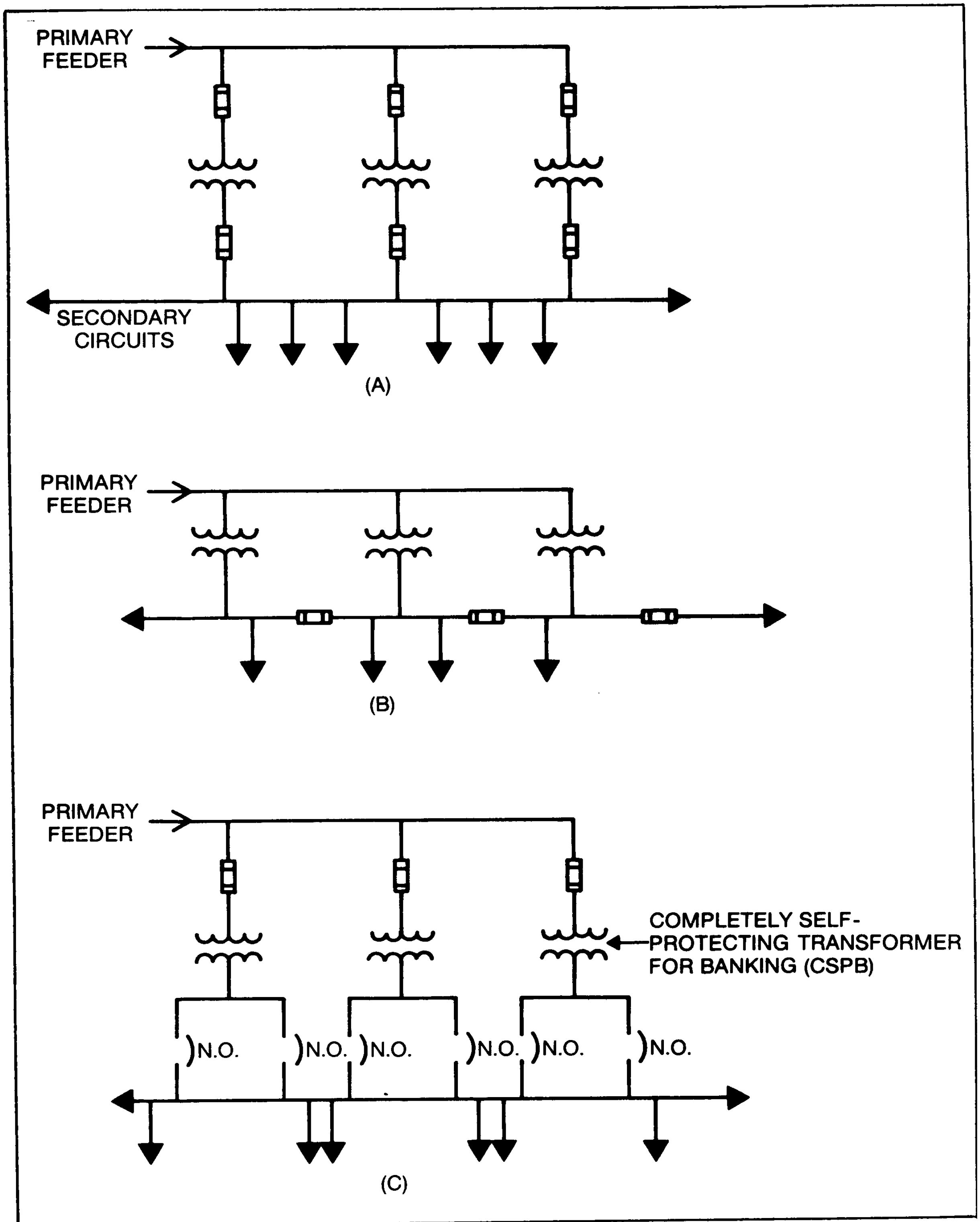


FIGURE 1-11
Secondary Banking Distribution System

(b) An available reliable power source to which critical loads are rapidly switched automatically when the prime source of power fails.

Emergency systems are frequently characterized by a continuous or rapid availability of electric power. This electric power operates for a limited time and is supplied by a separate wiring system. The emergency power system may in turn be backed by a standby power system if interruptions of longer duration are expected.

1.6.2.2 Standby Power Systems. Standby power systems are made up of the following main components:

(a) An alternate reliable source of electric power separate from the prime source.

(b) Starting and regulating controls when on-site standby generation is selected as the source.

(c) Controls which transfer loads from the prime or emergency power source to the standby source.

1.6.3 <u>Engine-Driven Generators</u>. These units are work horses which fulfill the need for emergency and standby power. They are available from fractional kW units to units of several thousand kW. When properly maintained and kept warm, the engine driven generators reliably come on line within 8 to 15 seconds. In addition to providing emergency power, engine-driven generators are also used for handling peak loads and are sometimes used as the preferred source of power. They fill the need of backup power for uninterruptible power systems.

1.6.3.1 Generator Voltage. The output of engine-driven generators used for emergency or standby power service is normally at distribution or utilization voltages. Generators rated at 500 kW or less operate at utilization voltages of 480Y/277 V, 208Y/120 V, or 240Y/120 V. Higher rated generators usually operate at nominal distribution system voltages of 2400 V, 4160 V, or 13,800 V.

1.6.3.2 Diesel Engine Generators. The ratings of diesel engine generators vary from about 2.5 kW to 6500 kW. Typical ratings for emergency or standby power service are 100 kW, 200 kW, 500 kW, 750 kW, 1000 kW, 1500 kW, 2000 kW, and 2500 kW. Two typical operating speeds of diesel engine generators in emergency and standby service are 1800 rpm and 1200 rpm. Lower speed units are heavier and costlier, but are more suitable for continuous power while nearly all higher speed (1800 rpm) sets are smaller.

1.6.3.3 Gasoline Engine Generators. Gasoline engines are satisfactory for installations up to approximately 100 kW output. They start rapidly and are low in initial cost as compared to diesel engines. Disadvantages include: higher operating costs, a great hazard due to the storing and handling of gasoline, and a generally lower mean time between overhaul.

1.6.3.4 Gas Engine Generators. Natural gas and liquid propane (LP) gas engines rank with gasoline engines in cost and are available up to about 600 kW. They provide quick starting after long shutdown periods because of the fresh fuel supply. Engine life is longer with reduced maintenance because of the clean burning of natural gas.

1.6.3.5 Gas Turbine Generators. Gas combustion turbine generators usually range in size from 100 kW to 20 MW, but may be as large as 100 MW in utility power plants. The gas turbines operate at high speeds (2000 to 5000 rpm) and drive the generators at 900 to 3600 rpm through reduction gearing. Gas turbine generator voltages range from 208 V to 22,000 V. The gas turbine generator system has a higher ratio of kW to weight or to volume than other prime mover systems and operates with less vibration than the other internal combustion engines, but with lower fuel efficiency.

1.6.4 <u>Typical Engine Generator Systems</u>. The basic electrical components are the engine generator set and associated meters, controls, and switchgear. Most installations include a single generator set designed to serve either all the normal electrical needs of a building or a limited emergency circuit. Sometimes the system includes two or more generators of different types and sizes, serving different types of loads. Also, two or more generators may be operating in parallel to serve the same load. Automatic starting of multiple units and automatic synchronizing controls are available and practical for multiple-unit installations.

1.6.4.1 Automatic Systems. In order for engine-driven generators to provide automatic emergency power, the system must also include automatic engine starting controls, batteries, an automatic battery charger, and an automatic transfer device. In most applications, the utility source is the normal source and the engine generator set provides emergency power when utility power fails. The utility power supply is monitored and engine starting is automatically initiated once there is a failure or severe voltage or frequency reduction in the normal supply. Load is automatically transferred as soon as the standby generator stabilizes at rated voltage and speed. Upon restoration of normal supply, the load is transferred back to the normal source and the engine is shut down.

(a) Automatic transfer devices (ATD) for use with engine-driven generator sets are similar to those used with multiple-utility systems, except for the addition of auxiliary contacts that close when the normal source fails. These auxiliary contacts initiate the starting and stopping of the engine-driven generator. The auxiliary contacts include a paralleling contactor (PC) and a load-dumping contactor (LDC), both electrically operated and mechanically held.

1.6.4.2 Engine Generators (Parallel operation). Figure 1-12 shows a standby power system where failure of the normal source would cause both engines to automatically start. The first generator to reach operating voltage and frequency will actuate load dumping control circuits and provide power to the remaining load. When the second generator is in synchronism, it will be paralleled automatically with the first. After the generators are paralleled, power is restored to all or part of the dumped loads. This system is the ultimate in automatic systems requiring more complexity and cost than would be appropriate in most activity requirements.

(a) If one generator fails, it is immediately disconnected. A proportionate share of the load is dumped to reduce the remaining load to within the capacity of the remaining generator. When the failed generator is returned to operation, the dumped load is reconnected.

(b) When the normal source is restored, the load is transferred back to it and the generators are automatically disconnected and shut down.

1.6.4.3 Peak Load Control System. With the peak load control system shown in Figure 1-13, idle standby generator sets can perform a secondary function by helping to supply power for peak loads. Depending on the load requirements, this system starts one or more units to feed peak loads while the utility service feeds the base loads.

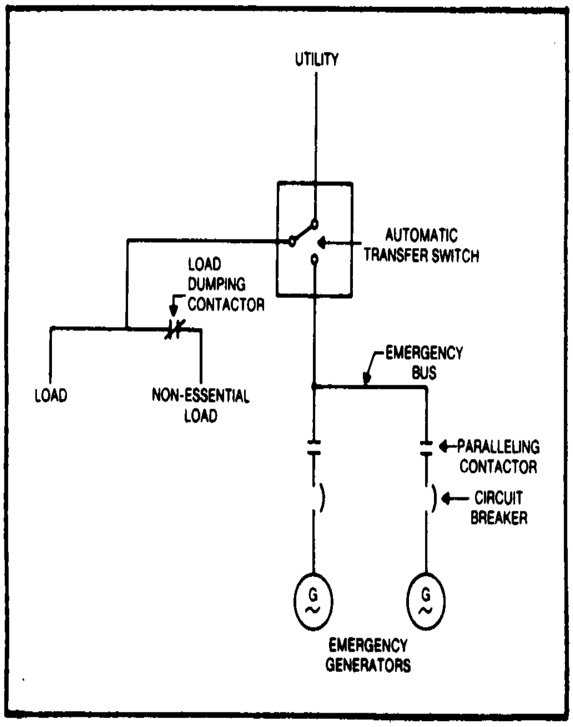
1.6.4.4 Combined Utility-Generator Operation. The system shown in Figure 1-14 provides switching and control of utility and on-site power. Two on-site buses are provided, (1) supply bus (primary) supplies continuous power for computer or other essential loads, and (2) an emergency bus (secondary) supplies on-site generator power to emergency loads through an automatic transfer device if the utility service fails.

In normal operation, one of the generators is selected to supply continuous power to the primary bus (EG1 in Figure 1-14). Simplified semiautomatic synchronizing and paralleling controls permit any of the idle generators to be started and paralleled with the running generator to alternate generators without load interruption. Anticipatory failure circuits permit load transfer to a new generator without load interruption. If the generator enters a critical failure mode, however, transfer to a new generator is made automatically with load interruption.

1.6.5 <u>Engine Generator Operation</u>.

1.6.5.1 Governors and Regulation. Governors can operate in two modes, droop and isochronous. With droop operation, the engine's speed is slightly higher at light loads than at heavy loads, while an isochronous governor maintains the same steady speed at any load up to full load:

$$\text{speed regulation} = \frac{(\text{no-load rpm}) - (\text{full-load rpm})}{(\text{full-load rpm})} \times 100\%$$



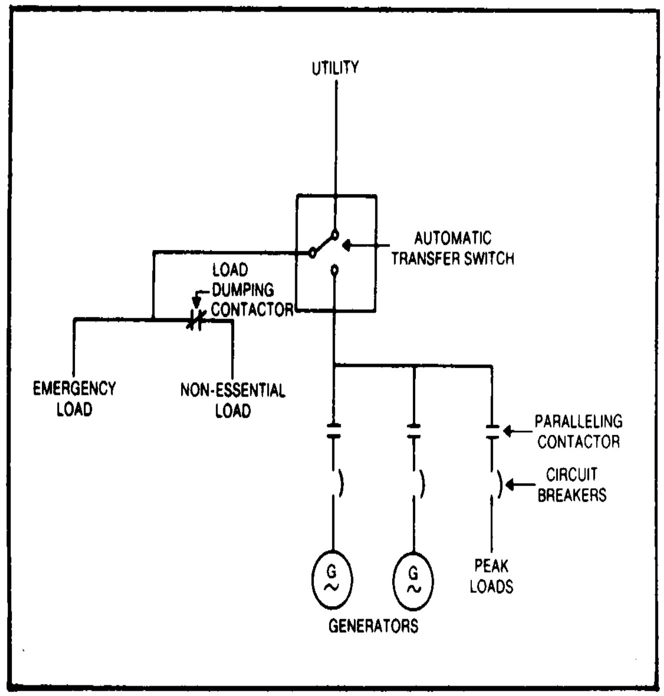


FIGURE 1-12
Engine Generators
(Parallel Operation)

FIGURE 1-13
Peak Load Control System

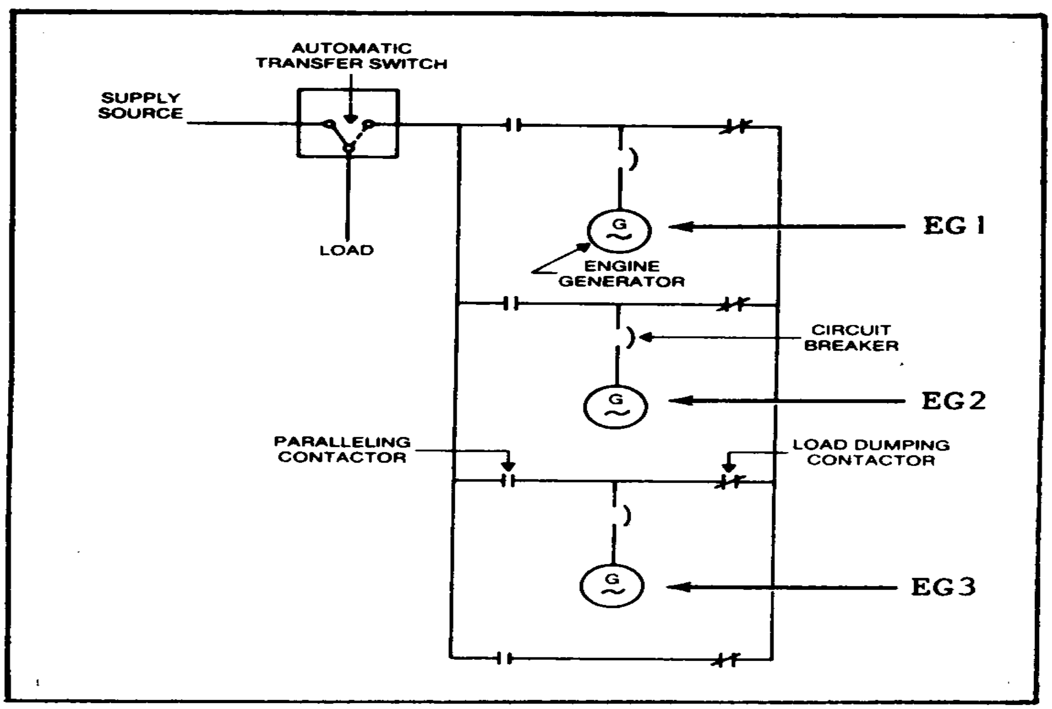


FIGURE 1-14
Combined Utility-Generator System

(a) A typical speed regulation for a governor operating with droop is 3 percent. Thus, if speed and frequency at full load are 1800 rpm and 60 Hz, at no load they would be approximately 1854 rpm and 61.8 Hz.

A governor would be set for droop only when operating in parallel (in this mode f = 60 Hz +/- 0) with a larger system or in parallel with another generator operating in the isochronous mode. In this way, system frequency is maintained and the droop adjustment controls load distribution among parallel engine generators.

(b) Under steady (or stable) load, frequency tends to vary slightly above and below the normal frequency setting of the governor. The extent of this variation is a measure of the stability of the governor. An isochronous governor should maintain frequency regulation within +/- 1/4 percent under steady load.

(c) When load is added or removed, speed and frequency dip or rise momentarily, usually for 1 to 3 seconds, before the governor causes the engine to settle at a steady speed at the new load.

1.6.5.2 Starting Methods. Most engine generator sets use a battery-powered electric motor for starting the engine. A pneumatic or hydraulic system normally is used only where starting of the electric plant is initiated manually.

1.6.6 Turbine-Driven Generators. Steam and petroleum are two general types of turbine prime movers for electrical generators currently available.

1.6.6.1 Steam Turbine Generators. Steam turbines are used to drive generators larger than those driven by diesel engines. Steam turbines are designed for continuous operation and usually require a boiler with a fuel supply and a source of condensing water. Because steam boilers usually have electrically powered auxiliary fans and pumps, steam turbine generators cannot start during a power outage. Steam turbine generators are, therefore, too large, expensive, and unreliable for use as an emergency or standby power supply. They may also experience environmental problems involving: fuel supply, noise, combustion product output, and heating of the condensing water. Steam turbines may also be used in cogeneration systems, where steam may be extracted from the turbine to serve process loads. In this configuration, no steam is condensed at the turbine exhaust, but rather the turbine operates with a back pressure and serves as a pressure reducing station.

1.6.6.2 Turbine Generators (Petroleum). The most common turbine-driven electric generator units employed for emergency or standby power today use gas or oil for fuel. Various grades of oil and both natural and propane gas may be used. Other less common sources of fuel are kerosene or gasoline. Gas or oil turbine generators can start and assume load within 40 seconds to several minutes for larger units. Gas turbine generators are generally used as emergency backup power sources because they start quickly, can assume full load in only one or two steps, and are less efficient than other prime movers. When there is a constant need for both process steam (or hot water) and electricity, the gas turbine generator (with an exhaust heat recovery system) may operate efficiently and continuously in a topping cycle cogeneration configuration. Combustion turbine generator sets exhibit excellent frequency control, voltage regulation, transient response, and behavior when operated in parallel with the utility supply.

1.6.7 Mobile Power Systems. One of the most important sources of emergency or standby power is mobile (transportable) equipment. For most industrial applications, mobile equipment will include only two types; diesel-engine-driven and gas-turbine-driven generators.

1.6.7.1 Ratings. Typical ratings of mobile generators range from kW to 2700 kW. Larger power ratings are satisfied by parallel operation.

1.6.7.2 Accessories. Mobile generators come anywhere from a stripped down unit with nothing but the prime mover and generator to units complete with soundproof chamber, control panel, relaying, switchgear, intake and exhaust silencers, fuel tank, battery, and other required operating and safety devices.

1.6.7.3 Navy Mobile Equipment. The Navy's Mobile Utilities Support Equipment (MUSE) program provides specialized, easily transportable utility modules for short-term support of shore utility systems. MUSE equipment includes generating units, substations, steam boilers, water treatment plants, and auxiliary equipment. Policy, procedures, and guidance for the management and use of MUSE are found in NAVFACENGCOM Instruction 11310.2. Detailed technical and general application data for the equipment are provided in the MUSE Application Guide, NEESA 50.1-001. Copies are available from Commanding Officer, Naval Energy and Environmental Support Activity, Port Hueneme, CA 93043-5014.

(a) For power plants, the nominal ratings of diesel engine generators are 750 kW to 2,500 kW. The gas turbine generators are rated at 750 kW.

(b) The nominal capacities of MUSE substations range from 1,500 kVA to 5,000 kVA. These substations are designed to provide maximum flexibility for transforming various system voltages. Presently, transformers rated 3,750 kVA and larger are two winding units, providing transformation between 13.2 kV or 11.5 kV and 4.16 kV. Either winding may be used as input or output. Units smaller than 3,750 kVA have three winding transformers. Their High Voltage (HV) winding nominal voltages are 13.2 kV or 11.5 kV; their Intermediate Voltage (IV) winding nominal voltages are 4.16 kV or 2.4 kV; and their Low Voltage (IV) winding nominal voltage is 480 V. These units can be operated with the HV or the IV acting as the input or output. The IV winding is an output winding only.

1.6.8 Uninterruptible Power Supply Systems. The UPS system includes all mechanical and electrical devices needed to automatically provide continuous, regulated electric power to critical loads during primary power system disturbances and outages. During normal conditions, the UPS system receives input power from the primary source and acts as a precise voltage and frequency regulator to condition output power to sensitive loads. During disturbance or loss of the input power, the UPS draws upon its stored-energy source to maintain the regulated output power. The stored energy source is usually sized to supply the UPS load for several minutes, until emergency or the normal input power is restored, or until the loads have undergone an orderly shutdown. There are two basic uninterruptible power supply systems: the rotary (mechanical stored-energy) system and the static (solid-state electronic system with storage-battery).

1.6.8.1 Rotary (Mechanical Stored-Energy) Systems. Upon loss of input power, rotary systems deliver uninterruptible power by converting the kinetic energy contained in a rotating mass to electric energy. These systems provide an excellent buffer between the prime power source and loads that will not tolerate fluctuations in voltage and frequency. Many types of systems are in use, but since static equipment has been used to replace rotary systems in the past ten years, only one configuration will be described.

The rotating flywheel no break system is shown in Figure 1-15. An induction motor is driven from the utility supply and this motor is directly coupled to an alternator with its own excitation and voltage regulating system. Coupled directly to the motor generator set is a large flywheel with one member of a magnetic clutch attached to the flywheel. The other half of the clutch is connected to a diesel engine or other prime power. Upon loss of alternating current input power, the generator is driven by energy stored in the flywheel until the engine can be started and drive the generator and flywheel. The voltage regulator maintains the voltage and, with proper selection of components to minimize the start and run times of the diesel engine, the frequency dip can be kept to approximately 1.5 to 2 Hz. Thus with a steady-state frequency of 59.5 Hz, the minimum transient frequency would be from 57.5 to 58 Hz. The time for the diesel to start, come up to speed, and assume the load would normally be from 6 to 12 seconds.

1.6.8.2 Static (Solid-State Electronic Circuitry) Systems. The basic static UPS system consists of a rectifier, battery, and DC-to-AC inverter. Static systems are very efficient power conversion devices. The advantages of static systems are stable operation, frequency unaffected by load changes, excellent voltage regulation, and fast transient response. These systems normally operate at 480Y/277 V or 208Y/120 V, 3-phase, 60 Hz input voltage and provide an output of 480Y/277 V or 280Y/120 V. Typical output specifications are: voltage regulation of +1 percent and frequency regulation of +0.001 percent. The ratings of these systems range from 50 VA to more than 1200 kVA. A UPS system can be designed with various combinations of rectifiers and inverters to operate in a nonredundant or redundant configuration.

(a) A nonredundant UPS system is shown in Figure 1-16. During normal operation, the prime power and rectifier supply power to the inverter, and also charge the battery which is floated on the direct current bus and kept fully charged. The inverter converts power from direct to alternating current for use by the critical loads. The inverter governs the characteristics of the alternating current output, and any voltage or frequency fluctuations or transients present on the utility power system are completely isolated from the critical load. When momentary or prolonged loss of power occurs, the battery will supply sufficient power to the inverter to maintain its output for a specified time until the battery has discharged to a predetermined minimum voltage. Upon restoration of the prime power, the rectifier section will again resume feeding power to the inverter and will simultaneously recharge the battery.

(b) The nonredundant UPS system reliability can be improved by installing a static switch and bypass parallel with the UPS as shown in Figure 1-17. When an inverter fault is sensed, the critical load can be transferred to the bypass circuit in less than 5 milliseconds. The static bypass adds about 20 percent to the cost of a nonredundant system, but is much more reliable.

(c) In the redundant UPS system shown in Figure 1-18, each half of the system has a rating equal to the full critical load requirements. The basic power elements (rectifier, inverter, and interrupter) are duplicated, but it is usually not necessary to duplicate the battery since it is extremely reliable. Certain control elements such as the frequency oscillator may also be duplicated. The static interrupters isolate the faulty inverter from the critical bus and prevent the initial failure from starting a chain reaction which might cause the remaining inverter to fail. The static bypass switch can also be applied to the redundant system.

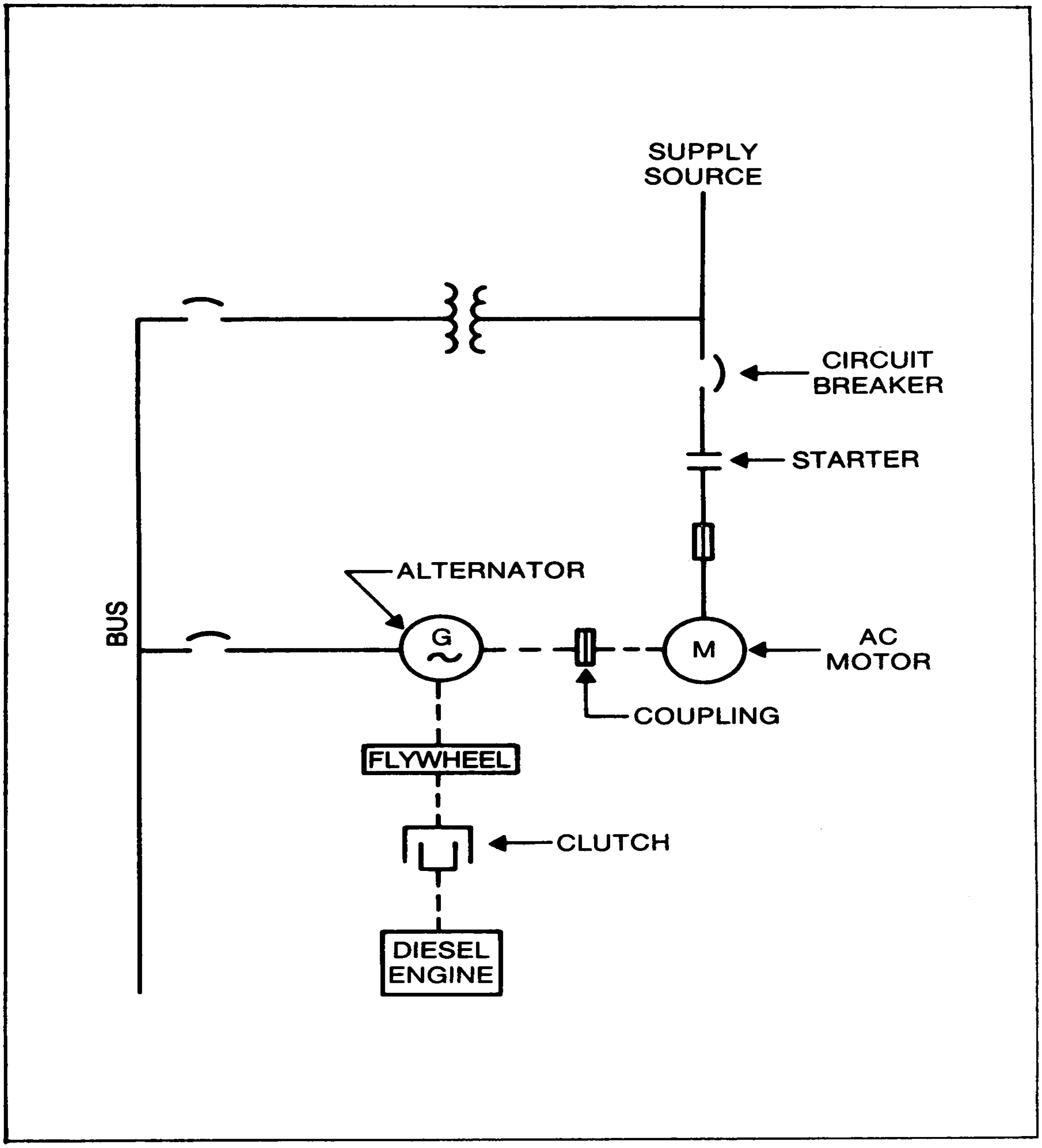


FIGURE 1-15
Rotating Flywheel No Break System

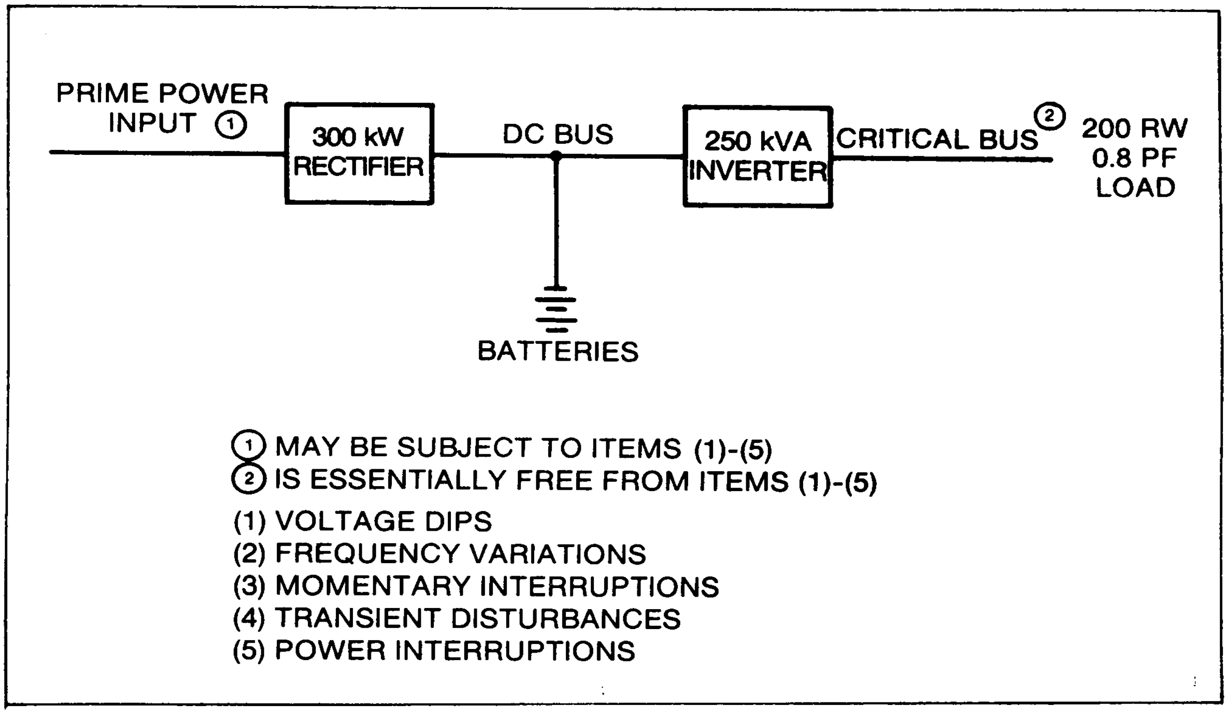


FIGURE 1-16
Nonredundant UPS System

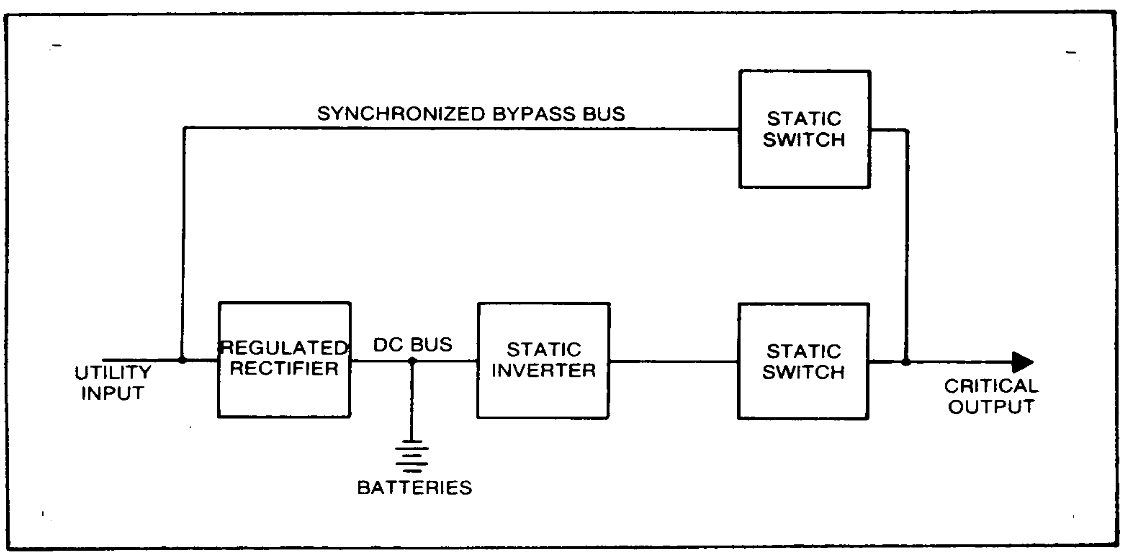


FIGURE 1-17
Nonredundant UPS System with Static Bypass

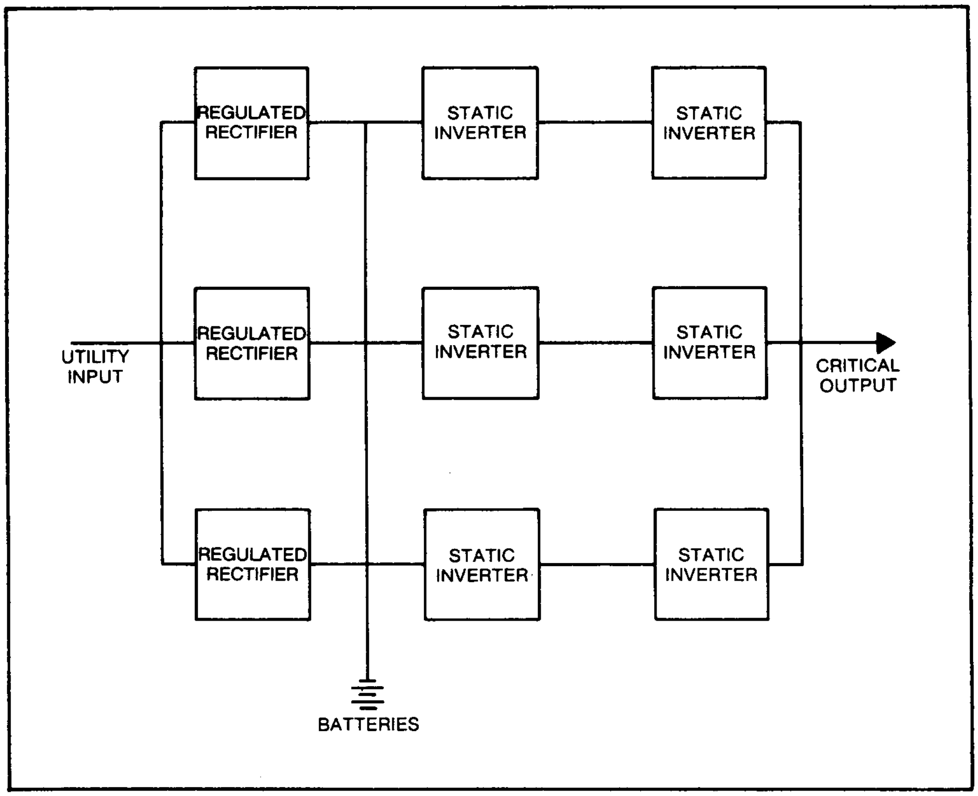


FIGURE 1-18
Redundant UPS System

CHAPTER 2. POWER DISTRIBUTION CABLE SYSTEMS.

2.1 CABLE SPECIFICATIONS. A cable is defined as a single conductor or an assembly of conductors covered by solid electrical insulation. Cable specifications generally start with the conductor and progress radially through the insulation and coverings. The following is a typical list of specifications:

(a) Number of conductors in cable.

(b) Conductor size (American Wire Gage (AWG), circular mil) and material.

(c) Insulation type.

(d) Voltage rating.

(e) Shielding system.

(f) Outer finishes (or sheath).

(g) Installation.

An alternate method of specifying cable is to furnish the ampacity of the circuit (amperes (A)), the voltage (phase to phase, phase to ground, grounded, or ungrounded), and the frequency, along with any other pertinent system data.

2.2 CABLE CONSTRUCTION. A typical cable is comprised of conductors shielded by various types of material. The cable may have one conductor or three conductors grouped as one.

2.2.1 <u>Conductors</u>. The two conductor materials in common use are copper and aluminum. Copper has historically been used for conductors of insulated cables primarily for its desirable electrical and mechanical properties. The use of aluminum is based mainly on its favorable conductivity-to-weight ratio (the highest of the electrical conductor materials), its ready availability, and the stable low cost of the primary metal.

2.2.1.1 Comparison Between Copper and Aluminum. Aluminum requires larger conductor sizes to carry the same current as copper. The equivalent aluminum cable, when compared to copper in terms of ampacity, will be lighter in weight and larger in diameter. For distribution, aluminum is commonly rated as equivalent to a copper conductor two AWG sizes smaller, which has almost identical resistance.

2.2.1.2 Classes of Conductors. Conductors are classified as solid or stranded. A solid conductor is a single conductor of solid circular section. A stranded conductor is composed of a group of small conductors in common contact. A stranded conductor is used where the solid conductor is too large and not flexible enough to be handled readily. Large solid conductors are also easily damaged by bending. The need for mechanical flexibility usually determines whether a solid or a stranded conductor is used, and the degree of flexibility is a function of the total number of strands. The strands in the stranded conductor are usually arranged in concentric layers about a central core. The smallest number of wires in a stranded conductor is three. The next number of strands are 7, 19, 37, 61, 91, 127, etc. Both copper and aluminum conductors may be stranded.

2.2.1.3 Conductor Sizes. Conductor sizes are ordinarily expressed by two different numbering methods: the AWG formerly known as the Browne and Sharpe gage, and the circular mil.

(a) The AWG or conductor sizes are numbered from 30 to 1, then continuing with 0, 00, 000, and 0000 (or 1/0, 2/0, 3/0, and 4/0 respectively). Number 30 is the smallest size and 4/0 the largest in this system. As an example of the actual physical size of the conductors commonly used in transmission and distribution work, the diameter of a number 8 AWG is 0.1285 inches and for a 4/0 AWG it is 0.460 inches.

(b) The circular mil is the unit customarily used in designating the cross sectional area of wires. A circular mil is defined as the area of a circle having a diameter of 1/1000 of an inch. The circular mils of cross section in a wire are obtained by squaring the diameter expressed as thousandths of an inch. For example, a wire with a diameter of 0.102 inches (102 thousandths of an inch) has a circular mils cross section of 102 X 102 = 10,404. Conductors larger than 4/0 AWG are designated in circular mils. These range from 250,000 to 2,000,000 circular mils (250 MCM or 250 kcmil to 2,000 MCM or 2,000 kcmil).

2.2.2 <u>Insulations</u>. Insulations can be classified in broad categories as solid, taped or special-purpose insulations. Basic insulating materials are either organic or inorganic. The following is a list of insulations commonly used:

(a) Thermosetting compounds (solid dielectric).
(b) Thermoplastic compounds (solid dielectric).
(c) Paper-laminated tapes.
(d) Varnished cloth-laminated tapes.
(e) Mineral inorganic insulation (solid dielectric granular).

Insulations in general use for voltages above 2 kV are listed below. Solid dielectrics of both plastic and thermosetting types are being more and more commonly used, while the laminated-type constructions, such as paper-lead cables are declining in popularity.

(a) Thermosetting Compounds:

- o Cross-Linked polyethylene (XLP or XLPE).
- o Ethylene propylene rubber (EPR).
- o Styrene butadiene rubber (SBR).
- o Silicone rubber.
- o Oil-base rubber.
- o Chlorosulfonated polyethylene rubber (CPR).
- o Butyl rubber.

(b) Thermoplastic Compounds:

- o Polyethylene (natural).
- o Polyvinyl chloride (PVC).

(c) Paper-laminated Tapes.

(d) Varnished Cloth-laminated Tapes.

2.2.3 Shielding of Higher Voltage Cable. For operating voltages below 2 kV, nonshielded constructions are normally used. Insulation shielding is required for all nonmetallic, sheathed, single-conductor cables operating above 2 kV and all metallic sheathed cables and multiconductor cables above 5 kV.

2.2.3.1 Procedure. Shielding is the practice of confining the electric field of the cable to the insulation surrounding the conductor by means of conducting or semiconducting layers, closely fitting or bonded to the inner and outer surfaces of the insulation. In other words, the outer shield confines the electric field to the space between conductor and shield. The inner or strand stress relief layer is at or near the conductor potential. The outer or insulation shield is designed to carry the charging currents and in many cases fault currents.

2.2.3.2 Purpose. Insulation shields have several purposes:

(a) Confine the electric field within the cable.

(b) Equalize voltage stress within the insulation, minimizing surface discharges.

(c) Protect cable from induced potentials.

(d) Limit electromagnetic or electrostatic interference (radio, TV, etc.).

(e) Reduce shock hazard (when properly grounded).

2.2.4 Cable Outer Finishes. Cable outer finishes or outer coverings are used to protect the underlying cable components from the environmental and installation conditions associated with intended service. The choice of cable outer finishes for a particular application is based on electrical, thermal, mechanical, and chemical considerations. Combinations of metallic and nonmetallic finishes are usually required to provide the total protection needed for the installation and operation.

2.2.4.1 Nonmetallic Finishes.

(a) There are outer coverings (extruded jackets) either thermoplastic or vulcanized, which may be extruded directly over insulation or over electrical shielding systems of metal sheaths or tapes, copper braid, or semiconducting layers with copper drain wires or spiraled copper concentric wires, or over multiconductor constructions. Commonly used materials include: polyvinyl chloride, nitrile butadiene/polyvinyl chloride (NBR/PVC), polyethylene, cross-linked polyethylene, polychloroprene (neoprene), chlorosulfonated polyethylene, and polyurethane. These materials provide a high degree of moisture, chemical, and weathering protection. They are reasonably flexible, provide some degree of electrical isolation, and are of sufficient mechanical strength to protect the insulating and shielding components from normal service and installation damage.

(b) A commonly used material is braided asbestos fiber. Asbestos braid is used on cables to minimize flame propagation, smoking, and other hazardous or damaging products of combustion which may be evolved by some extruded jacketing materials. Special industrial applications may require synthetic or cotton fibers applied in braid form. All fiber braids require saturants or coating and impregnating materials to provide some degree of moisture and solvent resistance as well as abrasive and weathering resistance.

2.2.4.2 Metallic Finishes. These materials are widely used when a high degree of mechanical, chemical, or short-time thermal protection of the underlying cable components may be required. Commonly used are interlocked galvanized steel, aluminum, or bronze armor; extruded lead or aluminum; strip formed, welded, and corrugated steel and aluminum; and spirally laid round or flat armor wires. The use of any of these materials will reduce flexibility of the overall cable, but flexibility must be sacrificed to obtain the other benefits.

(a) The unprotected interlocked armor provides a high degree of mechanical protection without significantly sacrificing flexibility. While not entirely impervious to moisture or corrosive agents, interlocked armor does provide protection from thermal shock by acting as a heat sink for short-time localized exposure. Where corrosion and moisture resistance are required, in addition to mechanical protection, an overall jacket of extruded material may be used. Commonly used interlocked armor materials are: galvanized steel, aluminum (for less weight and general corrosion resistance), and marine bronze and other alloys (for highly corrosive atmospheres).

(b) Longitudinally corrugated metal sheaths (corrugations or bellows formed perpendicular to the cable axis) have been used for many years in direct-burial communications cables, but only recently has this method of cable core protection been applied to control and power cables. The sheath material may be of copper, aluminum, a corrosion resistant steel or copper alloy, or a bimetallic composition of materials selected to best meet the intended service.

(c) Lead or lead alloys are used for industrial power cable sheaths for maximum cable protection in underground manhole and tunnel or underground duct distribution systems subject to flooding. While not as resistant to crushing loads as interlocked armor, its very high degree of corrosion and moisture resistance makes lead attractive in the above applications. Protection from installation damage can be provided by an outer jacket of extruded material.

(d) Extruded aluminum, copper, die-drawn aluminum, or copper sheaths are used in certain applications for weight reduction and moisture penetration protection. While more crush resistant than lead, aluminum sheaths are subject to electrolytic attack when installed underground. Under these conditions, aluminum sheathed cable should be protected with an outer extruded jacket.

(e) A high degree of mechanical protection and longitudinal strength can be obtained by using spirally wrapped or braided round steel armor wire. This type of outer covering is frequently used in submarine cable and vertical riser cable for support.

2.2.5 <u>Single-conductor and Multiconductor Constructions</u>. Single-conductor cables are usually easier to handle and can be furnished in longer lengths than multiconductor cables. Multiconductor constructions give smaller overall dimensions than an equivalent single-conductor cable, providing a space advantage.

2.3 CABLE RATINGS AND SELECTION CRITERIA. Cables come in various sizes. The size of a cable depends on the ampacity or voltage rating of the cable. Cables may contain various conductor sizes, and the electrical characteristics of the cable depends on the conductor size used.

2.3.1 <u>Electrical and Environmental Specifications</u>. The selection of power cables involves the consideration of various electrical and environmental conditions. These conditions include the quantity and characteristics of the power being distributed and the degree of exposure to adverse mechanical and thermal stresses. The selection of conductor size is based on the following criteria:

2.3.1.1 Voltage rating.

2.3.1.2 Load current criteria (as related to loadings, thermal effects of the load current, mutual heating, losses produced by magnetic induction, and dielectric losses).

2.3.1.3 Emergency overload criteria.

2.3.1.4 Voltage drop limitations.

2.3.1.5 Fault current criteria.

2.3.2 Voltage Rating. The selection of the cable insulation (voltage) rating is based on: the phase-to-phase voltage of the system in which the cable is to be applied, the general system category (depending on whether the system is grounded or ungrounded), and the time in which a ground fault on the system is cleared by protective equipment. It is possible to operate cables on ungrounded systems for long periods of time with one phase grounded due to a fault. This results in line-to-line voltage stress across the insulation of the two ungrounded conductors. Such cable, therefore, must have greater insulation thickness than a cable used on a grounded system (where it is impossible to impose full line-to-line potential on the other two unfaulted phases for an extended period of time). Consequently, 100 percent voltage rated cables are applicable to grounded systems provided with protection which will clear ground faults within one minute. 133 percent rated cables are required on ungrounded systems where the clearing time of the 100 percent level category cannot be met, and when there is adequate assurance that the faulted section will be cleared within one hour. 173 percent voltage level insulation is used on systems where the time required to deenergize a grounded section is indefinite.

2.3.3 Load Current Criteria. The manufacturer's ampacity recommendations should be used as load current criteria. The following publications contain ampacity tables for power cables.

(a) IEEE S-135-1-1962, Power Cable Ampacities, Copper Conductors.

(b) IEEE S-135-2-1962, Power Cable Ampacities, Aluminum Conductors.

Ampacity tables indicate the minimum size conductor required, however, conservative engineering practice, future load growth considerations, voltage drop, and short circuit considerations may require the use of larger conductors.

2.3.3.1 Skin and Proximity Effects. Careful consideration must be given when grouping cables, as de-ratings resulting from mutual heating may limit capacity. Paralleling two or more smaller size cables should be considered over installation of conductors (larger than 500 MCM) because the current carrying capacity, per circular mil of the conductor, decreases for alternating current circuits (due to skin effect and proximity effect). The reduced ratio of surface to cross-sectional area of larger size conductors is a factor in the reduced ability of the larger cable to dissipate heat. Cables larger than 500 MCM are also more difficult to handle during installation. When cables are used in multiple sets, consideration must be given to the phase placement of the cable to minimize the effect of reduced ampacity due to unbalanced distribution of current in the cables. Length of multiple sets should be the same.

2.3.3.2 Ambient Temperature. Cables must be de-rated when in proximity to other loaded cables or heat sources, or when the ambient temperature exceeds the ambient temperature at which the ampacity (current carrying capacity) tables are based. The normal ambient temperature of a cable installation is the temperature of the environment in which the cable is installed with no load being carried on the cable.

2.3.3.3 Surrounding Medium. The thermal characteristics of the medium surrounding the cables are of primary importance in determining the current carrying capacity of the cables. The type of soil in which the cable or duct bank is buried has a major effect on the current carrying capacity of the cables. Porous soils, such as gravel and cinder fill, usually result in higher temperatures and lower ampacities than sandy or clay soil. The moisture content of the soil has a major effect on the current carrying capacity of cables. In dry sections of the country, cables may have to be de-rated, or other precautions taken, to compensate for the increase in thermal resistance due to the lack of moisture. On the other hand, in ground which is continuously wet or under tidewater conditions, cables may carry higher than normal currents.

2.3.4 EmergencyOverload Criteria. Normal loading limits of insulated wire and cable are determined based on many years of practical experience. These limits account for a rate of insulation deterioration that results in the most economical and useful life of such cable systems. The anticipated rate of deterioration equates to a useful life of approximately 20 to 30 years. The life of cable insulation may be halved, and the average thermal failure rate almost doubled for each 5 to 15°C increase in normal daily load temperature. The normal daily load temperature is the average conductor temperature over a typical 24 hour period. It reflects both the change in ambient temperature and the change in conductor temperature due to daily load fluctuations. Additionally, sustained operation over and above maximum rated operating temperatures or ampacities is not an effective or economical practice, because the temperature rise is directly proportional to the conductor loss, which increases as the square of the current. The intensified voltage drop may also increase the risks to equipment and service continuity. Maximum emergency overload temperatures for various types of insulation have been established and are available as a practical guide. Operation at these emergency overload temperatures should not exceed 100 hours per year, and such 100 hour overload periods should not exceed five during the life of the cable.

2.3.5 Voltage Drop Criteria. The supply conductor, if not of sufficient size, will cause excessive voltage drop in the circuit, and the drop will be in direct proportion to the circuit length. Proper starting and running of motors, lighting equipment, and other loads having heavy inrush currents must be considered. It is recommended that the steady state voltage drop in distribution feeders be no more than four percent.

2.3.6 Fault Current Criteria. Under short-circuit conditions the temperature of the conductor rises rapidly then, due to the thermal characteristics of the insulation, sheath, and surrounding materials, it cools off slowly after the short-circuit condition is cleared. A transient temperature limit for each type of insulation for short-circuit durations not in excess of 10 seconds has been established, and many times this criterion is used to determine minimum conductor size. Insulated Power Cable Engineers Association (IPCEA) standards define the maximum conductor temperature limits allowable under worst-case fault conditions.

2.4 TYPES OF CABLE INSTALLATIONS. There are a variety of ways to install power distribution cables. Each method ensures distribution of power with a unique degree of reliability, safety, economy, and quality for any specific set of conditions. These conditions include the electrical characteristics of the power system, the distance and terrain of distribution, and the expected mechanical and environmental conditions.

2.4.1 Open-Wire. Open-wire construction consists of uninsulated conductors on insulators which are mounted on poles or structures. The conductor may be bare or it may have a thin covering for protection from corrosion or abrasion. The attractive features of this method are its low initial cost and the fact that damage can be detected and repaired quickly. On the other hand, the uninsulated conductors are a safety hazard and are also highly susceptible to mechanical damage and electrical outages resulting from short circuits caused by birds or animals. Proper vertical clearances over roadways, walkways, and structures are critical. Exposed open-wire circuits are also more susceptible to the effects of lightning than other circuits, however, these effects may be minimized by the use of overhead ground wires and lightning arresters. In addition, there is an increased hazard where crane or boom truck use may be involved. In some areas contamination on insulators and conductor corrosion can result in high maintenance costs.

2.4.2 Aerial Cable. Aerial cable consists of fully insulated conductors suspended above the ground. This type of installation is used increasingly, generally for replacing open wiring, where it provides greater safety and reliability and requires less space. Properly protected cables are not a safety hazard and are not easily damaged by casual contact. They do, however, have the same disadvantage as open-wire construction, requiring proper vertical clearances over roadways, walkways, and structures.

2.4.2.1 Supports. Aerial cables may be either self-supporting or messenger-supported. They may be attached to pole lines or structures. Self-supporting aerial cables have high tensile strength for this application. Cables may be messenger-supported either by spirally wrapping a steel band around the cables and the messenger or by pulling the cable through rings suspended from the messenger.

2.4.2.2 Distance. Self-supporting cable is suitable for only relatively short distances, with spans in the range of 100-150 feet. Messenger-supported cable can span relatively large distances, of over 1000 feet, depending on the weight of the cable and the tensile strength of the messenger. For this reason, aerial cable that must span relatively large distances usually consists of aluminum conductors to reduce the weight of the cable assembly. The supporting messenger provides high strength to withstand climatic rigors or mechanical shock. It may also serve as the grounding conductor of the power circuit.

2.4.3 Above-Ground Conduits. @Rigid steel conduit systems afford the highest degree of mechanical protection available in above-ground conduit systems. Unfortunately, this is also a relatively high-cost system. For this reason their use is being superseded, where possible, by other types of conduit and wiring systems. Where applicable, rigid aluminum, intermediate-grade steel conduit, thin-wall EMT, intermediate-grade metal conduit, plastic, fiber and asbestos-cement ducts are being used.

2.4.4 Underground Ducts. Underground ducts are used where it is necessary to provide a high degree of safety and mechanical protection, or where above-ground conductors would be unattractive.

2.4.4.1 Construction. Underground ducts use rigid steel, plastic, fiber, and asbestos-cement conduits encased in concrete, or precast multi-hole concrete with close fitting joints. Clay tile is also used to some extent. Where the added mechanical protection of concrete is not required, heavy wall versions of fiber and asbestos-cement and rigid steel and plastic conduits are direct buried.

2.4.4.2 Cables. Cables used in underground conduits must be suitable for use in wet areas, and protected against abrasion during installation.

2.4.5 Direct Burial. Cables may be buried directly in the ground where permitted by codes and only in areas that are rarely disturbed. The cables used must be suitable for this purpose, that is, resistant to moisture, crushing, soil contaminants, and insect and rodent damage. While direct-buried cable cannot be readily added to or maintained, the current carrying capacity is usually greater than that of cables in ducts. Buried cable must have selected backfill. It must be used only where the chance of disturbance is unlikely. The cable must be suitably protected, however, if used where the chance of disturbance is more likely to occur. Relatively recent advances in the design and operating characteristics of cable fault location equipment and subsequent repair methods and material have diminished the maintenance problem.

2.4.6 Underwater (Submarine) Cable. Submarine cable is used only when no other cable system can be used. It supplies circuits that must cross expanses of water or swampy terrain.

2.4.6.1 Construction. Submarine cable generally consists of a lead sheathed cable and is usually armored. Insulation material should be XLP or EPR, except when paper insulation is justified because of its high resistance to, and freedom from, internal discharge or corona. Multiconductor construction should be used, unless limited by physical factors. The lead sheathing usually consists of a copper-bearing lead material, however, other alloys may be required when special conditions warrant nonstandard sheathing. The most common type of armoring material used for submarine cables is the spirally wrapped round galvanized steel wire. In this type of cable, asphalt impregnated jute is usually applied over the lead sheath and the wire armor is applied over the jute to reduce mechanical damage and electrolytic corrosion. An additional covering of the asphalt impregnated jute may be applied over the wire armor. Nonmetallic sheathed cables are sometimes suitable for certain submarine applications. The cable must be manufactured specifically for submarine service and, generally, has an increased insulation thickness. The cable may require wire armor and should have electrical shielding for all voltage ratings above 600 V.

2.4.6.2 Installation. Submarine cable should lie on the floor of the body of water and should have ample slack so that slight shifting caused by current or turbulence will not place excessive strain on the cable. Where the cable crossing is subject to flow or tidal currents, anchors are often used to prevent excessive drifting or shifting of the cable. In addition to laying cables directly on the bottom, burying cable in a trench using the jetwater method should be considered. Cables must be buried in waters where marine traffic is present. The depth of burial should be enough to prevent damage caused by dragging anchors, which may be in excess of 15 feet for large ships on sandy bottoms. Warning signs located on shore at the ends of the submarine cable should be provided to prohibit anchoring in the immediate vicinity of the cable.

2.4.7 Grounding of Cable Systems. For safety and reliable operation, the shields and metallic sheaths of power cables must be grounded. Without such grounding, shields would operate at a potential considerably above ground. Thus, they would be hazardous to touch, and would incur rapid degradation of the jacket or other material intervening between shield and ground. This is caused by the capacitive charging current of the cable insulation which is approximately 1 milliampere (mA) per foot of conductor length. This current normally flows at a power frequency between the conductor and the earth electrode of the cable, normally the shield. In addition, the shield or metallic sheath provides the fault return path in the event of insulation failure, permitting rapid operation of the protection devices.

2.4.7.1 Grounding Conductor. The grounding conductor, and its attachment to the shield or metallic sheath, normally at a termination or splice, should have an ampacity no lower than that of the shield. In the case of a lead sheath, the grounding conductor must be able to carry the available fault current over its duration without overheating. Attachment to shield or sheath is frequently by means of solder, which has a low melting point; thus an adequate area of attachment is required.

2.4.7.2 Grounding Methods. The cable shield lengths may be grounded at both ends or at only one end. If grounded at only one end, any possible fault current must traverse the length from the fault to the grounded end, imposing high current on the usually very thin shield conductor. Such a current could damage or destroy the shield, and require replacement of the entire cable rather than only the faulted section. With both ends grounded, the fault current would divide and flow to both ends, reducing the duty on the shield, with consequently less chance of damage. There are modifications of both systems. In one, single-ended grounding may be attained by insulating the shields at each splice or sectionalizing point, and grounding only the source end of each section. This limits possible shield damage to only the faulted section. Multiple grounding, rather than just double-ended grounding, is simply the grounding of the cable shield or sheath at all access points, such as manholes or pull boxes. This also limits possible shield damage to only the faulted section.

2.5 POWER SYSTEM APPLICATIONS. A power system consists of transmission and distribution systems. The transmission system is typically of higher voltage and is usually referred to as a high side of the system. The distribution system is called a low side of the system. The two systems are usually connected by means of a transformer to transform the high voltage to low voltage.

2.5.1 Transmission System. Three-phase 3-conductor circuits are universally used in transmission systems. Transmission circuits consist of overhead or underground cables, or some combination of both.

2.5.1.1 Overhead Systems. Overhead circuits consist of aerial cables or open-wire conductors carried on poles or towers. Aluminum conductors have, to a large degree, replaced copper in overhead installations. Conductor sizes most commonly used vary from No. 2 AWG to 556 kcmil aluminum cable steel reinforced (ACSR) or stranded aluminum alloy.

An aluminum cable stranded around a steel core sized to give the required strength is known as ACSR. Other cables are aluminum conductor alloy-reinforced (ACAR) and all aluminum-alloy conductor (AAAC).

2.5.1.2 Underground Systems. In older areas, transmission circuits are often 3-conductor lead-covered cables. Cross-linked polyethylene and ethylene-propylene rubber are replacing lead. Ordinarily, a 3-conductor copper cable varying in size from 1/0 AWG to 500 kcmil is installed in underground conduits. Aluminum cable is seldom used in underground installations because these cables are larger than copper cables of equal ampacity.

2.5.2 Primary Distribution System. A 3-phase 3-wire system is commonly used in primary distribution.

2.5.2.1 Overhead Primaries. The conductor sizes most commonly used in overhead primaries range from No. 4 AWG ACSR to 336.4 kcmil stranded aluminum. Laterals, or branches, are often No. 4 or No. 2 AWG ACSR, but feeders run to the larger sizes. Aluminum, ACSR, and alloys of aluminum have largely displaced copper from primary circuit construction, although they may be specified on a copper-equivalent basis. Aerial cable is often used for primary conductors where clearances are too close for open wire or tree trimming is not practicable. The cable in some cases comprises three rubber-insulated, neoprene-insulated, or polyethylene-insulated conductors lashed to a bare messenger which serves as the neutral for 3-phase circuits. In other cases, the phase conductors are supported from the messenger by insulating spacers; this construction is commonly called spacer cable. Single-phase taps, in either case, are usually one insulated conductor and messenger or an insulated conductor with neutral strands spiralled around it.

2.5.2.2 Underground Systems. The conductor sizes most commonly used in underground primary distribution vary from No. 6 AWG to 500 kcmil copper. Feeders are usually 3- or 4-conductor cable, while laterals may be single-conductor because of the requirement for numerous transformer taps. On some systems, interconnected cable sheaths are used for the neutral conductor; others use a separate bare neutral or fourth conductor in the cable. Stranded aluminum conductors and aluminum sheaths have been used in some cases, but the increased outside diameter usually requires excessive duct space. Recent improvements in polyethylene insulation have extended the use of aluminum-conductor cable for direct-buried systems where overall size is not detrimental.

CHAPTER 3. POWER SYSTEM ELECTRICAL EQUIPMENT.

3.1 MAJOR APPARATUS. This chapter provides information regarding the requirements for, and the application of, major apparatus used in an electric power distribution system. More detailed information on this apparatus is available in trade standards, as well as in manufacturers' publications and NAVFAC MO-200.

3.1.1 System Components. The major system components described in this chapter are:

(a) Transformers.
(b) Voltage Regulators.
(c) Switches.
(d) Power Circuit Breakers.
(e) Automatic Circuit Reclosers.
(f) Power Capacitors.

3.1.2 Voltage Classes. Power equipment is normally rated according to the nominal system voltage. In equipment terminology, the voltage ratings fall into four classes:

(a) Low voltage - 600 V or less.
(b) Medium voltage - above 600 V to 72,500 V.
(c) High voltage - above 72,500 V to 242,000 V.
(d) Extra-high voltage - above 242,000 V to 800,000 V.

The equipment discussed in this chapter will generally be in the low and medium voltage classes.

3.1.3 Codes and Standards. In general, system designs and installation practices are governed by regulations in the National Electric Code (NEC) and the National Electric Safety Code (NESC). The NEC contains regulations governing the installation of electrical conductors and equipment within or on public and private buildings, mobile homes, recreational vehicles, float dwellings, and other premises such as yards, carnivals, parking lots and industrial substations. The NESC covers standards for safeguarding people from hazards arising from installation, operation and maintenance of electrical conductors and equipment. The provisions contained in the NEC define minimum requirements only, and are not intended to be used as design specifications. Minimum standards relating to electrical equipment have been established by the National Electrical Manufacturers Association (NEMA), the Institute of Electrical and Electronics Engineers (IEEE), and the American National Standards Institute (ANSI).

3.2 TRANSFORMERS. Transformers are an essential part of any electrical system. They come in various sizes and voltage ratings. Transformers are used for transforming power from one voltage level to another.

3.2.1 Fundamental Transformer Principles. A transformer consists of a magnetic core built up of silicon steel laminations with two sets of coils wound around the core. These coils are called the primary and secondary windings. This combination may be used to derive a voltage higher or lower than the voltage immediately available. The supply voltage is applied to the primary winding, whether it is the higher or lower voltage winding. The other winding, to which the load is connected, is termed the secondary winding. Since electromagnetic induction can only take place when the magnetic flux is continually varying, transformers can only be used in alternating current circuits.

3.2.1.1 Open-Circuit Characteristics. If an alternating electromotive force (emf) is applied to the terminals of the primary winding of a transformer with the secondary winding open-circuited (nothing connected between the secondary terminals), a very small current will flow in the primary circuit. The exciting current has a magnetizing current component that establishes the mutual magnetic flux that induces an emf in both primary and secondary windings. Since the primary and secondary windings are wound on the same core, and the magnetizing flux is common to the two windings, the voltage induced in a single turn of each winding will be the same, and the induced voltages in the primary and secondary windings are therefore in direct proportion to the number of turns in those windings. The exciting current also has a core loss component that accounts for the power absorbed by the hysteresis and eddy-current losses in the core.

3.2.1.2 Load Characteristics. The application of a load to the secondary side of the transformer produces a considerable change in the internal phenomena. When the secondary circuit is closed, a secondary current flows, the value of which is determined by the magnitude of the secondary terminal voltage and the impedance of the load circuit. The secondary load current produces in the core a load flux that is in phase with the secondary current, however, the secondary load current is immediately balanced by a primary load current of such a value that the primary and secondary load ampere-turns are equal. The secondary load flux is similarly counteracted by a primary load flux which is in phase with the primary load balancing current, and therefore in phase opposition to, and of the same magnitude as, the secondary load flux. Therefore, the core is left in its initial state of magnetization corresponding to the magnetizing current component of the exciting current; this explains why the iron loss is independent of the load. The total current in the primary circuit is the phasor sum of the primary load current and the no-load exciting current.

Low core loss transformers, made of a new amorphous type alloy, are still in the prototype development stage for most types of transformers. There are several test programs under way with utilities in different parts of the country in which selected.groups of these new type transformers have been placed in service in a test program to monitor long term performance of the units on overhead distribution circuits. Westinghouse has present capacity for 2400 unit/year in sizes 10 to 75 kVA and for primary voltages of 2.4 to 19.9 kV. Units for the typically larger three-phase substation applications are not yet readily available, as the transformer manufacturers are limited by the width of the amorphous steel material, as well as the quantity of material that is available from the Allied Corporation, which has the patent on this material. There are presently at least three manufacturers offering amorphous steel distribution type transformers for commercial use.

3.2.2 Losses. A transformer has three distinct circuits; electric, magnetic, and dielectric. Each of these circuits incurs losses, which may be subdivided as follows:

(a) Losses in the electric circuit.

- I^2R loss due to load currents.
- I^2R loss due to no-load exciting current.
- Eddy-current loss in conductors due to leakage fields.

(b) Losses in magnetic circuit.

- Hysteresis loss in core laminations.
- Eddy-current loss in core laminations.
- Stray eddy-current loss in core clamps, bolts, and other attachments.

(c) Loss in the dielectric circuit. This loss is small for all voltages up to 50 kV, and is consequently included in the no-load losses.

3.2.2.1 No-Load and Load Losses. The various losses are normally grouped as follows:

(a) No-load losses (commonly called iron losses).

- I^2R loss due to no-load exciting current.
- Hysteresis loss in core laminations.
- Eddy-current loss in core laminations.
- Stray eddy-current loss in core clamps, bolts and other attachments.
- Loss in the dielectric circuit.

In practice only the hysteresis and eddy-current losses are of importance in transformers. These losses are constant for a given applied voltage and unaffected by the load on the transformers. The dielectric losses are also functions of the primary and secondary voltages, but vary slightly with the temperature of the windings affected by the load on the transformer. The copper loss due to the magnetizing current is generally negligible and is independent of the load for a given excitation. This magnetizing current loss is very small in well designed and well constructed transformers, since this current does not usually exceed 5 percent of the full-load current, and in larger transformers may even be as low as 1 to 2 percent.

(b) Load losses (commonly called copper losses or short-circuit losses).

- I^2R loss due to load currents.
- Eddy-current loss in conductors due to leakage fields.

The I^2R losses due to load and exciting currents are inherent in the transformer design. The losses are determined by the length of the windings and the frame dimensions. The loss due to the additional current required to maintain the rated output is usually negligible. The eddy-current loss is set up by stray magnetic fields. This loss is also inherent in the transformer design and is usually calculated as a percentage of the I^2R loss. The I^2R losses are functions of the transformer core and winding design, and depend upon voltage transformation ratios, winding conductor sizes, and magnetic core dimensions and loss characteristics. The core hysteresis and eddy-current losses are a function of core dimensions, magnetic materials, and lamination thicknesses.

3.2.3 Insulation. Insulation mediums used in power transformers are either liquid or gas. In both cases some solid insulation for major separations is used. Solid insulation separates the high-voltage winding from the low-voltage winding. Liquid systems include oil, askarel, and high-fire-point liquids such as silicone. The gas systems include air, nitrogen, and fluorogases (such as sulfur hexafluoride). The selection of the insulation medium is dictated mainly by the installation site and cost.

3.2.3.1 Oil. Low cost, high dielectric strength, and ability to recover after dielectric overstress make mineral oil the most widely used transformer insulating material. Due to its flammable property, oil-insulated transformers are normally used for outdoor installations. Indoor installations require vaults and venting or fire suppression systems.

3.2.3.2 Askarel. Askarel is a generic term for a group of nonflammable synthetic chlorinated hydrocarbons used as electrical insulating media. Each manufacturer of askarel transformers applied a special name for this material. For example, Inerteen(R) is the trade name for the nonexplosive insulating and cooling liquid produced by Westinghouse. Inerteen(R), nearly water white in color, is produced by chlorination of biphenyl (a common chemical). The resulting polychlorinated biphenyls (PCBs) are relatively insoluble in water but soluble in fat, and are extremely persistent in the environment. While Inerteen(R) is generally regarded as being nontoxic but carcinogenic to humans, very high standards of control against pollution must be exercised. The combustion of Inerteen(R) and other askarels has been known to create dioxins as a solid residue or dust. In the public sector, there have been several well documented fires in which askarel filled transformers have become involved in large building fires. In each case, a dioxin residue was found which caused additional environmental problems in cleanup and repair after the fire incident.

Askarel liquids have been classified as toxic to animals and humans by the Environmental Protection Agency (EPA). As of 1 October 1977, the EPA no longer allows the manufacture of PCB fluids or the sale of askarel-filled transformers. To avoid an uncontrolled discharge to the environment, the users of askarel-insulated transformers must monitor and dispose of PCB liquid in accordance with applicable standards. (See ANSI C107.1-1974, Guidelines for Handling and Disposal of Capacitor- and Transformer-Grade Askarels, Containing Polychlorinated Biphenyls; and IEEE Standard 76-1974, Guide for Acceptance and Maintenance of Transformer Askarel in Equipment.)

3.2.3.3 High-Fire-Point Insulating Liquids. In the late 1970s, less-flammable, nontoxic, high-fire-point (greater than 3000C) fluids were introduced to replace askarel as a transformer dielectric (insulating) fluid. These fluids are designated as either polydimethylsiloxane (silicone) or high-molecular-weight hydrocarbons. These liquids will burn, but they do so very slowly and release much less heat than flammable mineral oil. They are also nontoxic, unlike askarel. Because of these characteristics, transformers insulated with high-fire-point liquid may be installed inside building areas not containing vaults, liquid confinement areas, or fire suppression systems. Although it is rarely economical to do so, askarel transformers may be drained, flushed, and refilled with a high-fire-point liquid. The kVA rating of a retro-filled transformer must be decreased for continuous service. The National Electric Code (NEC) contains installation information for less-flammable liquid insulated transformers. The Factory Mutual Research Corporation lists high-fire-point qualifying liquids.

3.2.3.4 Air or Gas. The ventilated dry-type transformer has applications in distribution systems, and may be installed indoors without a vault. The sealed or gas-filled dry-type transformer has very limited use, due principally to the higher price. Nitrogen and air-insulated transformers are generally limited to 15 kV and lower operating voltages.

3.2.3.5 Basic-impulse Insulation Level (BIL). It is characteristic of most insulations that the maximum voltage which they can successfully withstand varies inversely with the duration of the voltage. Since power systems are subject to various types of overvoltage, some of long and some of short duration, power distribution equipment is usually required to withstand at least two different types of dielectric tests. The first are the so-called low-frequency (60-cycle) tests, usually of one minute duration, that establish the ability of the insulation to withstand moderate overvoltage of relatively long duration. The others are the impulse tests designed to prove that the insulation will not break down on voltage surges of high magnitude but short duration, such as those produced by lightning. The impulse test commonly used consists of the application of a very short duration full-wave voltage surge of a specified crest value to the equipment insulation. The crest value of the wave the insulation can withstand without breakdown is the BIL. To simplify the design and application of electrical equipment, a series of Standard BIL's have been established. As an example, for a reference insulation class rated at 15 kV, the BIL is 110 kV.

3.2.4 Cooling. Removal of heat caused by losses is necessary to prevent excessive internal temperature which would shorten the life of the insulation. The transformer life is cut in half by a 10°C rise in temperature. The general classes of cooling are: self-cooled, forced-air or forced-oil-cooled, and water-cooled. The basic types of cooling are referred to by standard designations.

3.2.4.1 Oil Immersed Self-Cooled (OA). In this type of transformer the insulating liquid circulates by natural convection and heat is dissipated over the radiating surface. The OA transformer is a basic type and serves as a standard for capacity rating.

3.2.4.2 Oil Immersed Self-Cooled/Forced-Air-Cooled (OA/FA). This type of transformer is basically an OA unit with the addition of external fans to increase heat dissipation from the radiators. It is usually possible to obtain between 15 percent - 33 1/3 percent more capacity relative to the OA rating with the fans running. The OA/FA transformer is applicable in situations that require short-time peak loads to be carried recurrently, without affecting normal expected transformer life.

3.2.4.3 Oil Immersed Self-Cooled/Forced-Air Cooled/Forced-Oil (OA/FA/FOA). The rating of an OA transformer can be increased by the addition of fans and oil pumps. Automatic controls responsive to liquid temperature are normally used to start the fans and pumps in a selected sequence as transformer loading increases. The increase in capacity over the OA rating is usually obtained in two stages: first stage - 33 1/3 percent and second stage - 66 2/3 percent. A variation of these triple-rated transformers is the OA/FOA/FOA type.

3.2.4.4 Oil Immersed Forced-Oil Cooled Forced-Air Cooled (FOA). This type of transformer uses external oil-to-air heat exchangers requiring both air fans and fluid pump for all operating conditions. FOA transformers cannot, without pumps and fans, carry rated loads.

3.2.4.5 Oil Immersed Water Cooled (OW). The cooling water runs through coils of pipe which are in contact with the insulating oil of the transformer. The oil flows around the coils of pipe by natural convection, thereby effecting the heat transfer to the cooling water. This type of transformer has no self-cooled rating. The OW/A type is water cooled and self cooled.

3.2.4.6 Oil Immersed Forced-Oil Cooled with Forced-Water Cooled (FOW). This type of transformer is similar to the FOA unit, except that external oil-to-water heat exchangers are used.

3.2.4.7 Dry-Type Transformers. In dry-type transformers, available at voltage ratings of 15 kV and below, cooling is accomplished primarily by internal air flow. Three classes of dry-type transformers are: self-cooled (AA), forced-air cooled (AFA) and self-cooled/forced-air cooled (AA/FA).

3.2.5 Transformer Impedance. The turns ratio of a-two-winding transformer determines the ratio between primary and secondary terminal voltages, when the transformer load current is zero. When load is applied to the transformer, however, the load current encounters an apparent impedance within the transformer which causes the ratio of terminal voltages to depart from the actual turns ratio. This internal impedance consists of two components:

(a) A reactance derived from the effect of leakage flux in the windings.

(b) An equivalent resistance which represents all losses traceable to the flow of load current, such as conductor I^2R loss and stray eddy-current loss.

3.2.5.1 Percent Impedance. Transformer impedance is conveniently expressed in percent, and is determined by the ratio of impedance voltage to rated primary voltage. In three-phase transformer banks, it is usually appropriate to refer both impedance voltage and rated voltage to a line-to-neutral basis. Percent impedance is also equal to measured ohmic impedance, expressed as a percentage of base ohms. Base ohms for a transformer circuit is defined as the rated current (per phase) divided into rated voltage (line-to-neutral), with the rated current derived from the self-cooled rating of the transformer.

3.2.5.2 Impedance Values. The percent impedance values depend on various factors including the number of windings, particular phase, high and low voltage ratings, transformer kVA rating, and the insulation medium and cooling class. In general, impedance values increase with higher voltage and kVA ratings. For most purposes, the impedance of power transformers may be considered equal to their reactances because the resistance component is negligible.

3.2.5.3 Fault Current Stresses. The standard transformer is designed with a limited ability to withstand the stresses imposed by external short circuits. The maximum short-circuit current magnitude and duration that a transformer can endure without incurring thermal and magnetic damage varies with transformer size and the number of phases. ANSI Std. C57.1200 defines the fault current withstand capability for liquid-immersed transformers.

3.2.6 Regulation. The full load regulation of a power transformer is the change in secondary voltage, expressed in percent of rated secondary voltage, that occurs when the rated kVA output at a specified power factor is reduced to zero, with the primary voltage maintained constant. The percent regulation can be calculated from the measured impedance characteristics at any load and power factor. The regulation can also be determined by loading the transformer according to the required conditions at rated voltage and measuring the rise in secondary voltage when the load is disconnected.

3.2.6.1 Effect of Variables. The percent regulation varies inversely with respect to the power factor (being lowest at unity power factor) and directly with the impedance. Transformers having very good regulation (low impedance), however, are also susceptible to higher fault currents. This relationship is an important factor in transformer engineering.

3.2.6.2 Voltage Taps. Voltage taps permit incremental changes in the ratio of the primary to secondary voltage transformation. Voltage tap adjustments can be used to maintain a constant secondary voltage despite changes in the primary voltage or secondary load currents.

(a) The most commonly selected tap arrangement is the manually adjustable no-load type, consisting of four 2 1/2 percent steps or increments from the nominal primary voltage rating. These tap positions are usually numbered 1 through 5, with the number 1 position providing the greatest number of effective turns. With a constant incoming voltage, selecting a higher voltage tap (lower tap number) will lower the output voltage. Tap positions can be manually changed only when the transformer is removed from service.

(b) Load Ratio Control automatically adjusts the primary to secondary voltage ratio +/- 10 percent in incremental steps, and can be controlled by a voltage sensor at the transformer secondary or at a remote location of the distribution system. Usually there are 32 (5/8 percent) steps to enable close voltage control over the range of +/- 10 percent. Automatic tap changing is accomplished by a voltage regulating relay and motor mechanism.

3.2.7 Connections. Standard 3-phase two-winding power transformers are connected in various configurations. The transformers used in main substations and at other points in primary distribution systems are typically Delta primary and Wye secondary. Other transformations, used by the Navy, are the Wye-Delta, Wye-Wye, and Delta-Delta. Less commonly used transformations, include the ZigZag, Open-Delta, Scott, and Six-Phase Star.

3.2.7.1 Delta-Wye. The Delta-Wye connection is shown in Figure 3-1. The wye secondary with external neutral bushing provides a convenient neutral point for establishing a system ground, or a neutral conductor for phase-to-neutral load. The delta-connected primary winding minimizes the flow of third harmonic currents and eliminates zero-sequence currents in the supply lines to improve the supply system voltage wave shape and to allow detection and isolation of line-to-ground faults (zero-sequence currents is a significant factor in symmetrical components analysis terminology). The delta connection may be used whether the primary is connected to a three-wire or four-wire system. Principal applications of a Delta-Wye connections are stepping down to supply a four wire load and stepping up to supply a high-voltage distribution or transmission system.

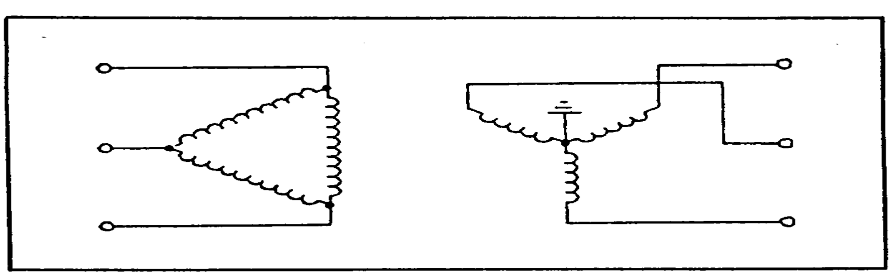


FIGURE 3-1
Delta-Wye

3.2.7.2 Wye-Delta. The Wye-Delta connection is shown in Figure 3-2. Wye-Delta connections are generally used for large-ratio step-down transformers. The primary is a wye connection due to the inherent mechanical and electrical advantages of wye circuits, while a delta connected secondary provides an improved waveform to loads.

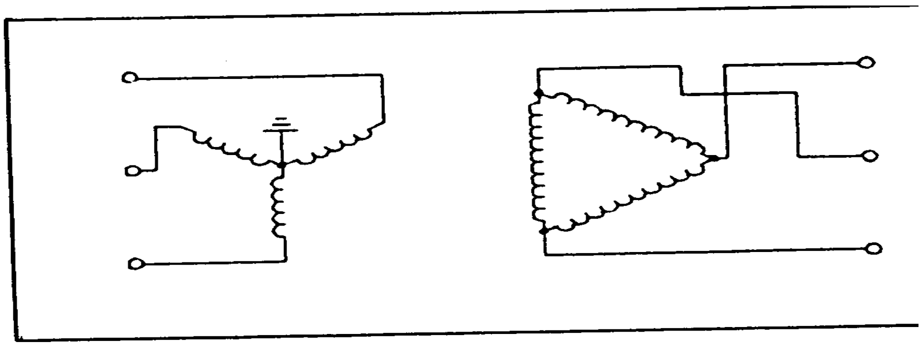


FIGURE 3-2
Wye-Delta

3.2.7.3 Wye-Wye. The Wye-Wye connection is shown in Figure 3-3. Wye-Wye connections are seldom used since they are subject to disturbances from harmonic voltages and currents. Unbalanced loads cannot be carried on the secondary unless the primary neutral is provided. For those applications which require a wye-wye transformation, a third winding, delta connected and designated as the tertiary is recommended to provide a low impedance path for zero-sequence currents. The third winding can also be used to serve an auxiliary load if external connection facilities are provided.

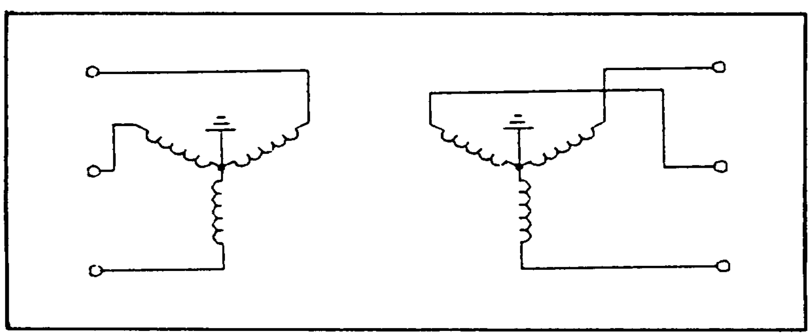


FIGURE 3-3
Wye-Wye

3.2.7.4 Delta-Delta. The Delta-Delta connection is shown in Figure 3-4. The Delta-Delta connection is also seldom used. It is used on Naval ships to enhance damage control. A phase to ground fault will be detected but does not trip breakers because there is minimal fault current.

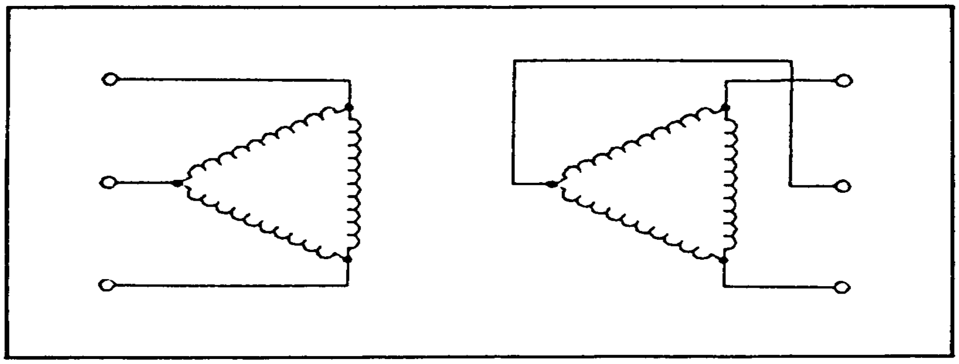


FIGURE 3-4
Delta-Delta

3.2.7.5 Zigzag. The Zigzag connection is shown in Figure 3-5. The interconnected wye connection is commonly referred to as the zigzag connection. It may be used with either a delta-connected winding or a wye-connected winding for step-up or step-down operation. In either case, the zigzag winding produces the same angular displacement as a delta winding and it provides a neutral for grounding purposes. A discussion of the internal connection of a three-phase zigzag transformer, with no secondary winding, can be found in subparagraph 3.2.11.2, Grounding Transformers.

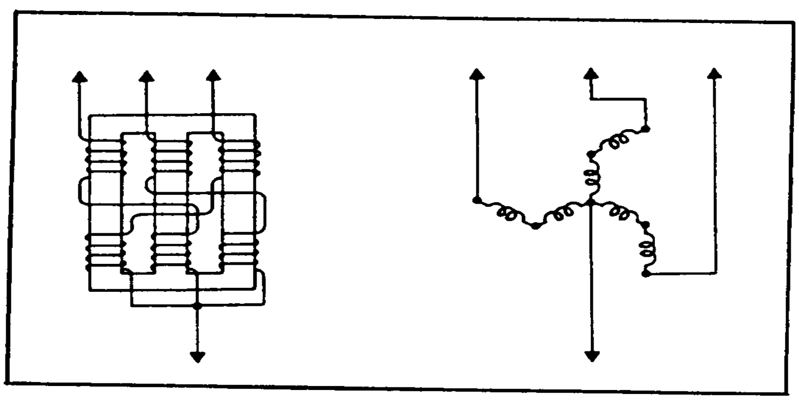


FIGURE 3-5
Zigzag

3.2.7.6 Open-Delta. The open-delta connection is shown in Figure 3-6. Under balanced conditions, an open-delta bank can be operated at slightly less than 58 percent of the throughput of an equivalent delta-delta bank; and the voltages and currents are, for practical purposes, the same as for a delta-delta bank. Open-delta banks have two important roles in power distribution. First, they allow operation at reduced initial investment on systems subject to future expansion. A balanced three-phase load can be served with an open-delta bank, allowing future expansions in load up to 72 percent of the open-delta rating, simply by adding the third transformer. Second, a distribution system, that is reasonably well balanced, can be operated at reduced load while one transformer is being serviced or replaced. This is particularly important in plants that can reduce throughput at low cost but cannot afford periods of shutdown for significant portions of the load being served.

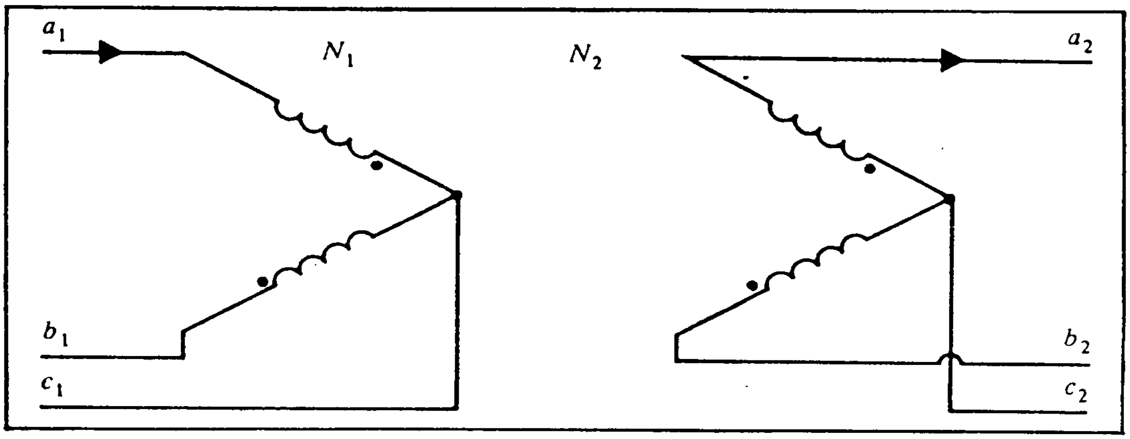


FIGURE 3-6
Open-Delta

3.2.7.7 Scott Connection. The Scott connection is a means of converting three-phase to two-phase transformations or vice versa. Usually, two identical transformers are purchased so that they will be interchangeable. This requires an 0.866 tap on one transformer and a midwinding tap on the other. The Scott connection is shown in Figure 3-7.

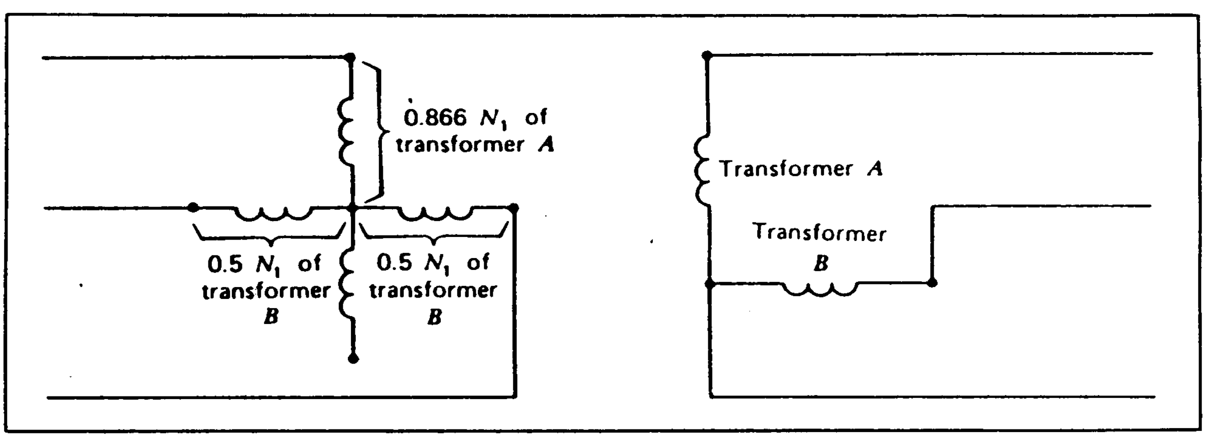


FIGURE 3-7
Scott Connection
(Three-Phase to Two-Phase Transformations)

3.2.7.8 Six-Phase Star. The six-phase star connection is shown in Figure 3-8. It provides a means for converting three-phase to six-phase transformations and is used in many rectifier and thyristor circuits where a path for DC current flow is required. The characteristic angle of a six-phase system is 60 degrees.

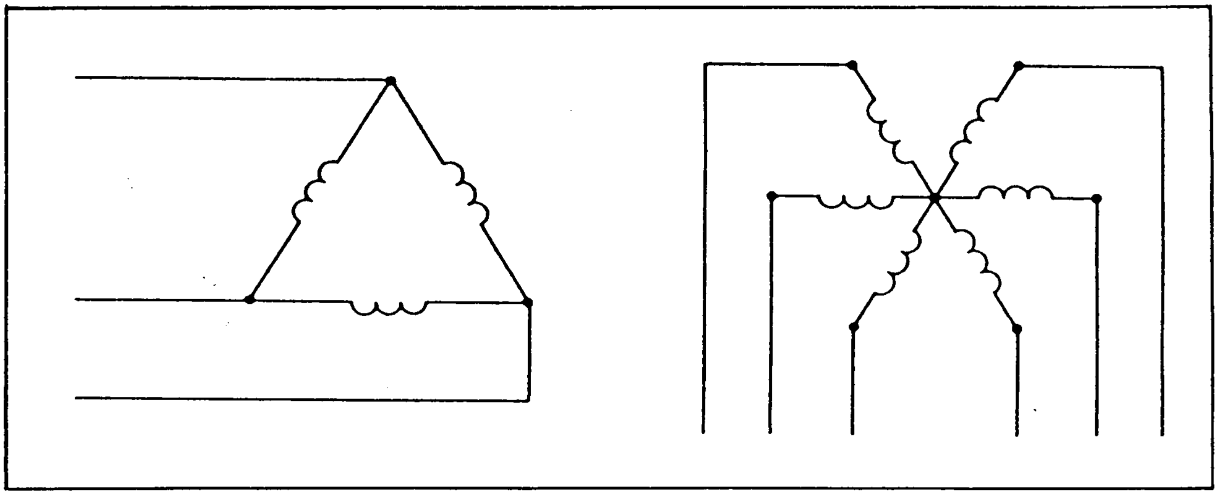


FIGURE 3-8
Six-Phase Star
(Three-Phase Delta to Six-Phase Star Connection)

3.2.8 Loading of Transformers. Ordinarily the kVA that a transformer should carry is limited by the effect of reactance on regulation or by the effect of load losses on system economy. At times it is desirable to ignore these factors and increase the kVA load until the effect of temperature on insulation life is the limiting factor. High temperature decreases the mechanical strength and increases the brittleness of fibrous insulation, making transformer failure increasingly likely, even though the dielectric strength of the insulation material may not be seriously degraded. Overloading of transformers should be limited by reasonable consideration of the effect on insulation and, consequently, transformer life.

3.2.8.1 Kilovolt-Amperes (kVA) Ratings. Ratings in kVA or megavolt-amperes (MVA) will include the self-cooled rating at a specified temperature rise, as well as the forced-cooled ratings if the transformer is so equipped. As a minimum consideration, the self-cooled rating should be at least equal to the expected peak demand.

3.2.8.2 Winding Temperature. The standard allowable average winding, of copper, temperature rise (by resistance test) for the modern liquid-filled power transformer is either 55°C/65°C or 65°C, based on an average ambient of 30°C (40°C maximum) for any 24 hour period. Since temperature distribution is uneven in most transformers, hottest-spot insulation temperature usually determines insulation life and, therefore, transformer loading. A 65°C rated transformer in a 30°C ambient environment is usually rated for a hottest spot temperature of 110°C.

3.2.8.3 Overloads. Transformers have certain overload capabilities, varying with ambient temperature, pre-loading, and overload duration. These capabilities are defined in ANSI Std. C57.92, Guide for Loading Mineral-Oil-Immersed Distribution and Power Transformers, and ANSI Std. C57.96, Guide for Loading Dry-Type Distribution and Power Transformers.

3.2.9 Parallel Operation. The theoretically ideal conditions for paralleling transformers are:

(a) Identical turns ratios and voltage ratings.
(b) Equal percent impedances.
(c) Equal ratios of resistance to reactance.
(d) Same polarity.
(e) Same phase angle shift.
(f) Same phase rotation.

3.2.9.1 Single-Phase Transformers. Only the first four conditions for paralleling transformers (listed above) apply to single-phase transformers, as there is no voltage transformation related to phase angle shift or phase rotation. All six conditions apply, however, to paralleling three-phase-banks of single-phase transformers. If the turns ratios are not the same, a circulating current will flow even at no load. If the percent impedance or the ratios of resistance to reactance are different, there will be no circulating current at no load, and the division of load between the loaded transformers will no longer be proportional to their kVA ratings.

3.2.9.2 Three-Phase Transformers. While the same transformer paralleling conditions apply to three-phase transformers, consideration must be given to the phase angle shift and to phase rotation. The transformers must have the same winding arrangement.

(a) Certain transformer connections as the Wye-Delta or Wye-Zigzag produce a 30° shift between the line voltages on the primary side and those on the secondary side. Transformers with these connections cannot be paralleled with transformers not having this shift such as Wye-Wye, Delta-Delta, Zigzag-Delta, or Zigzag-Zigzag.

(b) Phase rotation refers to the sequence in which the terminal voltages reach their maximum values. In paralleling, those terminals whose voltage maximums occur simultaneously are paired.

3.2.9.3 Power Transformer Practice. The preceding discussion covered the theoretically ideal requirements for paralleling. In actual practice good paralleling is obtained even though the actual transformer conditions deviate by small percentages from the theoretical ones.

(a) In order to insure maximum use of transformer capacity, and to prevent overloading of one transformer inadvertently, the criterion generally accepted is that the circulating current for any combination of ratios and impedances should not exceed ten percent of the full-load rated current of the smallest unit. This can generally be accomplished if the impedances are within 7.5 percent of each other, as this is the standard ANSI tolerance from a nominal specified value for a group of transformers that are manufactured to the same specifications. The X/R ratio of the transformers should also be within 7.5 percent of each other. A more detailed discussion of parallel operation of transformers with equations to evaluate whether parallel operation can be safely achieved, is contained in Chapter 5 of Transformers, Second Edition, K. L. Gebert and K. R. Edwards, American Technical Society, Chicago, IL.

(b) When it is desired to parallel transformers having widely different impedances, reactors or autotransformers having the proper ratio should be used. If a reactor is used, it is placed in series with a transformer having a lower impedance. It should have an impedance value sufficient to bring the total effective percent impedance of the transformer and reactor up to the value of the percent impedance of the second transformer. When an autotransformer is used, the relative currents supplied by each transformer are determined by the ratio of the two sections of the autotransformer. The autotransformer adds a voltage to the voltage drop in the transformer with the lower impedance and subtracts a voltage from the voltage drop in the transformer with the higher impedance. Autotransformers for use in paralleling power transformers are designed specifically for each installation.

3.2.10 Classifications. Transformers have many classifications which are useful in the industry to distinguish or define certain characteristics of design and application.

3.2.10.1 Distribution and Power. Transformers may be classified according to the rating in kVA. The distribution type covers the range of 3 kVA through 500 kVA, and the power type all ratings above 500 kVA or over 67 kV system voltage.

3.2.10.2 Insulation. Transformers may be classified by insulation type, as liquid and dry. Liquid insulated can be further defined according to the types of liquid: mineral oil, askarel, or other synthetic liquids. The dry-type grouping includes the ventilated and sealed gas-filled types.

3.2.10.3 Substation or Unit Substation. The title substation transformer usually denotes a power transformer with direct cable or overhead line termination facilities. This distinguishes it from a unit substation transformer designed for integral connection to primary or secondary switchgear, or both, through enclosed bus connections. The substation classification is further defined by the terms primary and secondary. The primary substation transformer has a secondary or load-side voltage rating greater than 1000 V, whereas the secondary substation transformer has a load-side voltage rating of 1000 V or lower.

3.2.11 Special Transformers. There are various transformers used in special applications, such as autotransformers, grounding, constant-current, furnace, and self-protected transformers.

3.2.11.1 Autotransformers. Autotransformers are constructed with a single winding per phase, such that part of the winding is common to both primary and secondary sides. The common portion is called the common winding, and the remainder is called the series winding. The high-voltage terminal is called the series terminal, and the low-voltage terminal is called the common terminal. Part of the power passes from one winding to the other by transformation, and the rest passes directly through without transformation. A solid connection exists between the primary and secondary circuits. This is generally of little consequence with low-voltage circuits, but with high-voltage systems the neutral point must be grounded for safe operation.

Autotransformer voltage transformation ratios rarely exceed 2:1. They are commonly used to connect two transmission systems at slightly different voltages, frequently with a delta tertiary winding. Similarly, autotransformers are used for generator step-up transformers to feed two different transmission systems.

3.2.11.2 Grounding Transformers. A grounding transformer is intended primarily for the purpose of providing a neutral point for grounding purposes. One such application could be grounding a Delta-connected system. Grounding transformers may be either of the Zigzag- or Wye-Delta type.

(a) The type of grounding transformer most commonly used is a zigzag three-phase transformer with no secondary winding. The internal connection of this transformer is illustrated in Figure 3-9. The impedance of the transformer to three-phase currents is high, so that when there is no fault on the system, only a small magnetizing current flows in the transformer windings. The transformer impedance to ground current, however, is low so that it allows high ground currents to flow. The transformer divides the ground current into three equal in-phase current components, flowing in the three windings of the grounding transformer.

(b) A Wye-Delta transformer can also be used as a grounding transformer. in this case the delta must be closed to provide a path for the zero-sequence current, but can be made up at any convenient voltage level. It may or may not be used to serve other loads. The wye winding must be of the same voltage rating as the circuit which is to be grounded.

3.2.11.3 Constant-Current Transformers. A constant-current transformer automatically maintains an approximately constant current in its secondary circuit under varying conditions of load impedance when its primary is supplied from an approximately constant-potential source. The moving coil design is the most commonly used type, having separate primary and secondary

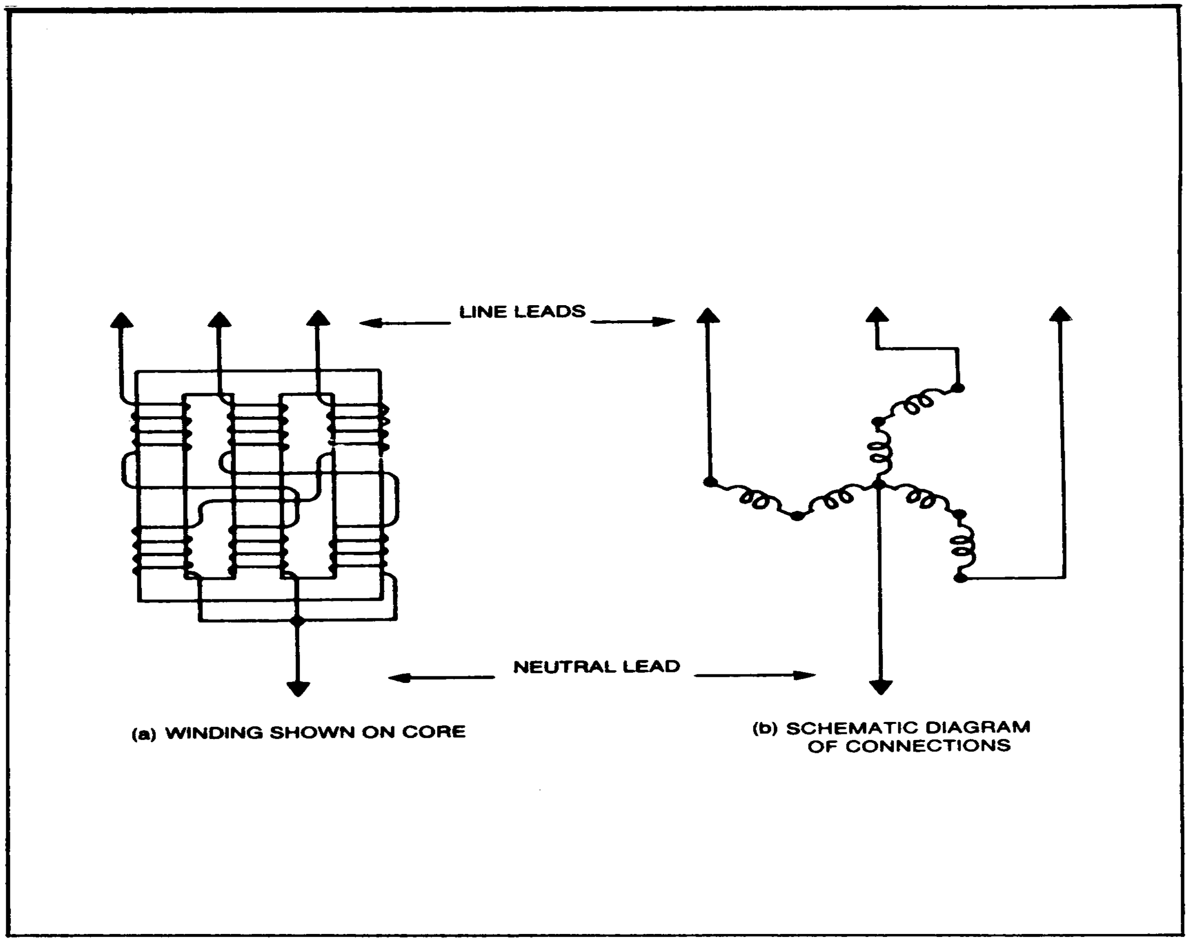


FIGURE 3-9
Zigzag Three-Phase Grounding Transformer

coils which are free to move with respect to each other, thereby varying the magnetic leakage reactance of the transformer. This reactance automatically adjusts itself to a value which, when added to the load impedance, permits a constant current to flow. Constant-current transformers are used primarily for series street lighting circuits. Standard output ratings are 10, 15, 20, 25 and 30 kW. The standard rated output current of these transformers is 6.6 or 20 A.

3.2.11.4 Furnace Transformers. Furnace transformers supply power to various types of electric furnaces. The secondary voltages are low, generally several hundred volts, and occasionally less than 100 V. Sizes range from a few kVA to over 50 MVA, with secondary currents over 60,000 A. High currents are obtained by parallel connection of many winding sections and collected by internal bus bars.

3.2.11.5 Self-Protected Transformers. Self-protected transformers generally have an internally mounted, thermally controlled secondary breaker for overload and short-circuit protection; an internally mounted protection link in series with the high-voltage winding to disconnect the transformer from the line in the event of an internal coil failure; and a lightning arrester, or arresters, integrally mounted on the outside of the tank for overvoltage protection.

3.3 VOLTAGE REGULATORS. The function of a transmission and distribution system is to deliver power to the user at a voltage that is within acceptable limits. It is impractical, however, to regulate large systems solely by means of generator regulators. Other devices for correcting the voltage, therefore, are commonly used throughout the system. These devices include transformers with automatic load-tap-changers, synchronous condensers, switched capacitors, and voltage regulators.

3.3.1 Definition. A voltage regulator (transformer type) is an induction device having windings in shunt with the primary circuit and secondary windings in series with the regulated circuit. Although similar in operation to transformer load-tap-changing equipment, voltage regulators are distinct pieces of power system apparatus.

3.3.2 Types of Voltage Regulators. There are three types of regulators; step, induction, and ferroresonant. The induction regulator was commonly used in the past for power circuits, however, it has been generally replaced by the less expensive and more serviceable step regulator. The ferroresonant transformer (FRT) has been used as a constant voltage transformer in low power applications (less than 1 kVA to approximately 15 kVA) for many years. With proper filtering, the FRT is now used quite often to serve sensitive electronic and computer equipment.

3.3.2.1 Step Voltage Regulator. The step voltage regulator is an autotransformer equipped with a mechanism capable of changing taps under load. Standard step regulators have a regulation range of +/- 10 percent of the applied voltage. This range is usually divided into thirty-two 5/8 percent steps so that each change represents a specific increment of voltage.

3.3.2.2 Induction Voltage Regulator. Induction voltage regulators operate on the transformer principle although their construction resembles that of a wound-rotor induction motor. The shunt winding is connected across the line and supplies excitation for the regulator. Upon excitation of the shunt winding, a voltage is induced in the series winding. Although it remains constant in magnitude, the phase relationship of the induced voltage, with respect to the voltage of the shunt winding, changes as the rotor is turned. The position of the rotor, therefore, determines how much buck or boost voltage is imparted by the regulator at any given time.

3.3.2.3 Ferroresonant Constant Voltage Transformer. The ferroresonant constant voltage transformer was patented in 1938. Generally, it consists of a resonant electrical circuit and a high leakage reactance magnetic circuit. The output voltage remains essentially constant for a wide range (+/- 15 percent) of input voltage. The principle of operation is a resonant circuit, consisting of a series coil and a capacitor, tuned to resonate at approximately 60 Hz. A saturable inductor is the secondary winding of the transformer and operates in saturation in the design input voltage range of the unit to deliver a constant output voltage. The output voltage is rich in harmonics (usually 20 percent or more harmonic distortion). For use with loads sensitive to these harmonics, extra filtering coils must be added to the output circuitry to reduce harmonic distortion to less than 3 percent. The FRT's are available in designs up to approximately 15 kVA and are usually used on low voltage (120 to 240 V) circuits. Higher power and voltage ratings are limited by the capacitor sizing and other methods of regulation are more economic at the higher voltage and power levels. These types of units are frequency sensitive. The units designed to operate at 60 Hz are not suitable for use at 50 Hz, which is the power source available in many foreign countries.

3.3.3 Ratings. Voltage regulators are rated in terms of the number of phases, capacity in kVA, primary voltage, percent regulation, and frequency. In addition, information concerning temperature rise, impedance, insulation level, type of cooling, method of making connections, and similar data is given on the nameplate.

3.3.3.1 kVA Rating. The kVA rating of a regulator is the product of the load amperes and the voltage of the series winding in kilovolts. Standard ratings of regulators are available up to 833 kVA single-phase and 2500 kVA three-phase for line voltages of 2500 V to 34,500 V. To enable regulation of 25,000 kVA circuits, 10 percent regulation units have a kVA regulated circuit reading ten times higher than that of the regulator kVA.

3.3.3.2 Insulation and Cooling. Standard regulators are oil-immersed and self-cooled. Units above 500 kVA can usually accommodate fans for forced cooling, adding up to 66 percent to the self-cooled rating.

3.3.4 Applications. Voltage regulators are installed on distribution systems to keep voltages at a selected value. The location of a regulator is determined by the type of loads and circuits served. Regulators are available for ground or pole installation.

3.3.4.1 Bus Regulators. Bus regulation is often used when a substation has two or more circuits with similar load characteristics and requirements. For such applications the regulator installation controls the voltage on the substation bus rather than on individual circuits. Voltage regulation of the bus can also be accomplished by equipping the station's power transformer with a load tap changing (LTC) mechanism.

3.3.4.2 Feeder Regulators. Feeder regulators maintain a constant voltage on a particular circuit with variation in load. They may be installed at a substation or located between the substation and the load being served. On long lines, or lines with critical loads, two or more regulator installations may be warranted in order to cope with the circuit requirements. These may be located either on the main feeder or branch feeder circuits.

3.3.5 <u>Regulator Control</u>. Most modern regulators are motor-operated and automatically controlled. Facilities are provided for the regulator to control the voltage at a point remote from the regulator location. The components required to automatically control a motor-operated regulator are:

(a) Voltage sensing device.
(b) Amplifying section.
(c) Motor drive.
(d) Line-drop compensator.

A voltage sensing device is connected through a potential transformer across the feeder or bus to be regulated. The voltage sensing device, which may be either a voltage-regulating relay or a static voltage sensor, operates a switch that controls the operating motor of the regulator. A current transformer connected in series with the regulated circuit has its secondary winding normally connected to a line-drop compensator. This line-drop compensator contains variable resistance and reactance (each independently adjustable) which represents the impedance of a regulated circuit. The voltage drop in the regulated circuit is, thus, easily detected by a proportional voltage drop across the compensator. Once adjusted, the compensator permits the regulator to hold constant voltage at a selected point on the circuit, regardless of load or power factor.

3.3.6 <u>Single- and Three-Phase Connections</u>. Single-phase regulators are applied to control the voltage on a single-phase circuit. They may, however, be applied to three-phase circuits and have some advantage over three-phase units that regulate all three phases in the same manner. Single-phase units, when applied to three-phase circuits, can be adjusted for separate regulation levels. A three-phase unit can only be adjusted for an average value of the three phase

3.3.7 Parallel Operation of Step Regulators. Special adaptations make it possible to operate step regulators in parallel, however, certain restrictions are imposed by each method. The choice of a method is dependent upon such factors as circuit impedances, proximity of units, and the types of equipment being paralleled. This is to prevent off-step operation, which could lead to excessive circulating current between regulators.

3.3.8 Bypassing Single-Phase Voltage Regulators. In order to provide continuity of service and to prevent injury to the regulator, special facilities and procedures are necessary for switching regulators on and off a line. The following are general procedures; individual manufacturer's instructions should be followed.

3.3.8.1 Disconnecting Regulator. Referring to Figure 3-10 (Bypass Switching Arrangement for Single-Phase Voltage Regulator), the sequence of operation for disconnecting a voltage regulator is summarized as follows:

(a) Place regulator control on manual and adjust to neutral position.

(b) Open the control power switch.

(c) Close switch D shorting series winding.

(d) Open switch C and then B.

(e) Open switch A, if used. This switch is required only when terminal S_2 - L_2 is not connected to the neutral or ground wire.

3.3.8.2 Connecting Regulator. Referring to Figure 3-10, the sequence of operation for connecting a voltage regulator is summarized as follows:

(a) Verify that the regulator control switch is in the manual position and that the regulator is in the neutral position.

(b) Close switch A, if used.

(c) Close switch B and switch C.

(d) Open switch D.

(e) Close the control power switch.

(f) Turn control switch from manual to automatic.

3.3.8.3 Regulator Bypassing Equipment. Equipment used to bypass regulators includes circuit breakers, interlocking switches, and cutouts with disconnecting blades. A convenient switching device is the regulator bypass switch, which includes switches B, C, and D of Figure 3-10, as an integral unit. When the regulator bypass switch is operated, the correct switching sequence occurs.

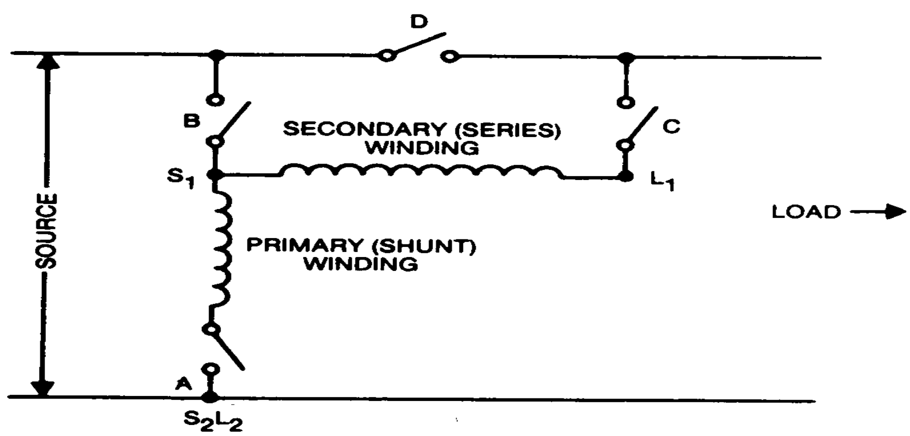


FIGURE 3-10
Bypass Switching Arrangement for Single-Phase Voltage Regulator

3.3.9 Bypassing Three-Phase Voltage Regulators. With the exception of the single-core, 3-phase induction regulator, the switching sequence of subparagraph 3.3.8 applies to each phase of a 3-phase regulator. In such cases, three identical sets of switches would be used. Since the single-core, 3-phase induction regulator has no neutral position within the regulation range where the series winding voltage is zero, special facilities must be provided.

3.3.10 Regulator Protection.

3.3.10.1 Surge Protection. As previously stated, regulators are constructed very much like autotransformers, having primary (shunt) and secondary (series) windings. Surge protection requirements for regulators are consequently very similar to those for transformers.

3.3.10.2 Short-Circuit Protection. Because voltage regulators are connected in series in the circuit, they may be subjected to exceptionally severe short-circuit currents. For this reason, current-limiting devices are often installed in the circuit to limit possible fault currents to a value that the regulator can withstand.

3.3.10.3 Thermal Protection. There is no inherent thermal protective device built into a regulator. Consequently, the operator must be watchful for overloads that may damage the regulator. Like transformers, regulators have some overload ability and may be overloaded under certain conditions.

3.4 SWITCHES. A switch is a device for making, breaking, or changing the connections in an electric circuit. Switches are normally divided into three classes relative to the operating medium; air, oil, and vacuum switches.

3.4.1 General Purpose. Air switches are an essential element of electrical power transmission and distribution systems. They provide positive, visible air-gap isolation for equipment, bus and line sections and facilitate examination, maintenance, and repair. Oil and vacuum switches are primarily used in underground distribution systems, especially where submersible switching equipment is required. In addition, oil switches are often used on capacitor circuits.

3.4.2 Ratings. Switches are rated in terms of one or more of the following characteristics; voltage, Basic-impulse Insulation Level (BIL), continuous current, short-time current, and interrupting current.

3.4.2.1 Voltage Rating. The voltage rating is a value assigned for the purpose of designating dielectric characteristics and should not be exceeded under normal operating conditions.

3.4.2.2 Basic-impulse Insulation Level. This is the reference insulation level expressed as the impulse crest value of withstand voltage of a specified full impulse wave (see subparagraph 3.2.3.5).

3.4.2.3 Continuous Current Rating. The continuous current rating is the designated limit of current in amperes that the switch will carry continuously without exceeding a maximum temperature rise of 30° above ambient. For switches having copper-to-copper contacts or the equivalent, this ambient may be 40°. For switches having all contacts silver-surfaced or the equivalent, this ambient may be 55°C. The limited heat storage capacity of a switch precludes any overload rating. Switches, therefore, should not be operated in excess of their continuous current rating, except under emergency conditions.

3.4.2.4 Interrupting Rating. The interrupting rating indicates the maximum short-circuit current that a switch can interrupt without sustaining damage. No switch should ever be operated (open or close) on an energized power system unless it has sufficient interrupting capacity. For personnel safety, this precaution cannot be overemphasized.

3.4.2.5 Short-Time Rating. All switches have a short-time current rating corresponding to the switch's ability to carry short-circuit current in the closed position. This rating incorporates the limitations imposed by both thermal and electromagnetic effects. The short-time current rating of a switch is the highest current that the switch is designed to carry without damage for specified short-time intervals. The short-time current rating consists of two values:

(a) That which the switch can carry for one cycle, referred to as its momentary rating.

(b) That which it can carry for four seconds.

Numerically, the momentary rating is 1.6 times the four-second rating.

3.4.3 <u>Types of Switches and Their Application</u>. There are a variety of switches used in the transmission and distribution of electric power. The switches are designed for specific purposes and operational conditions. In general, the switches are distinguished by the current handling capability; i.e., continuous, loadbreak or non-loadbreak, and fault current.

3.4.3.1 Air Switches.

(a) A disconnect switch is one used for; closing, opening, or changing the connections in a circuit or system, or for isolating purposes. It has no interrupting rating and is intended to be operated only after the circuit has been deenergized by some other means. Disconnect switches may be either hook- or gang-operated. A series-connected circuit breaker or circuit recloser should be open on all three phases before a disconnect switch is opened or closed.

(b) Air-break switches are normally mounted on top of their supporting structure and are gang-operated. They are either manually operated by means of an operating handle or electrically operated by means of a motor-operated mechanism. They are used to perform various switching assignments such as isolating transformers, bypassing circuit breakers, and for line sectionalizing (where small amounts of magnetizing or charging currents are to be interrupted).

(c) An interrupter switch can use either air or oil as its interrupting medium. Load-interrupter switches are used to interrupt transformer-magnetizing current, line-charging current, capacitor current to isolated banks, and load current within the limits of their rating. They are normally used where the cost of a circuit breaker with fault-interrupting ability cannot be justified and where the use of air-break switches is hazardous because of the danger of inconvenient and uncontrolled arcs. oad-interrupter switches differ from circuit breakers and fault interrupter switches in that they cannot interrupt overload or short-circuit currents. Interrupter switches may be either single-pole hook-stick operated or gang-operated, depending upon their location and application.

(d) A grounding switch is used to connect a circuit or a piece of apparatus to ground. Grounding switches are normally subdivided into two separate groups: manually operated and high-speed. Where a manually operated grounding switch is installed, it is normally connected to an air-break or gang-operated disconnect switch. It is used to effectively ground a line after the air-break or disconnect switch has isolated it. The manually operated grounding switch is generally interlocked with its associated switch so that the grounding switch cannot be closed until the disconnect is open. A high-speed grounding switch has a stored-energy mechanism capable of closing the switch automatically, within a specified rated closing time. The switch is opened either manually or by a power-operated mechanism. High-speed grounding switches are used to provide protection to a differential relayed area in coordination with a remote circuit breaker. Normally, the arrangements are such that the differential relay detects the fault and initiates the closing of the high-speed grounding switch and results in tripping the remote circuit breaker to clear the fault.

3.4.3.2 Oil Switches. An oil switch has its main contacts submerged in oil. Oil acts as an insulator to help quench the arc between the contacts. In addition, since the tank is airtight, the vaporized oil caused by the arc develops pressure which assists in breaking the arc. If the voltage is not very high, a three-pole switch can be placed in a single tank. At higher voltages, three separate tanks are used to make it impossible for a phase-to-phase fault to occur. Oil switches will normally open only load current. A separate trip coil is necessary to interrupt overload or fault currents. Oil switches are generally used in capacitor switching, distribution sectionalizing, and transformer primary switching.

3.4.3.3 Vacuum Switches. Vacuum switches (See Figure 3-11 for an example of a three-phase vacuum loadbreak switch) are interrupters which use vacuum chambers for contact separation. They are generally used to interrupt load, capacitor, or transformer magnetizing currents. Unlike oil switches, vacuum switches require virtually no maintenance. They can be used for submersible or padmount operation.

3.4.4 Switch Accessories. Switch accessories are devices that perform a secondary or minor duty as an adjunct or refinement to the primary operation of a switch or to assist in the operation of a switch. Some accessories that are commonly associated with switches are as follows:

3.4.4.1 Operating Mechanisms. The operating mechanism of a switch is a power-operated or manually-operated mechanism complete with an assembly of levers, mechanical linkages, and interphase connecting rods by which the contacts of all poles are actuated simultaneously.

3.4.4.2 Hook Sticks. A hook stick is a hook provided with an insulating handle (usually specially treated wood) for opening and closing hook-stick-operated switches. When not being used, hook sticks should be stored in a dry location.

3.4.4.3 Interlocks. An interlock is a device applied to two or more movable parts, preventing or allowing a movement of one part only when one or more other parts are locked in a predetermined position. An interlock system is a series of these devices applied to equipment to allow operation of the equipment only in a prearranged sequence. Switches used only for isolating purposes must be interlocked to prevent opening of the isolating switch under load, or the switch must be provided with a highly visible sign warning against opening the switch under load. Interlocks are classified into three main divisions: mechanical interlocks, electrical interlocks, and key interlocks.

3.4.4.4 Auxiliary Switches. Auxiliary switches are low-voltage switches that are attached to the operating mechanism of gang-operated switches. The open or closed position of auxiliary switches is governed by the position of the main contacts. Auxiliary switches are used for electrical interlocking, remote position indication, or control of electrically operated switches.

3.4.5 Operation. Disconnect switches, grounding switches, and air-break switches have no interrupting rating. It is, however, common practice to use air-break switches to interrupt small values of current and to use the following general rules.

3.4.5.1 Operation Rules.

(a) Prior to operating, check the circuit to see that no load is being carried by the switch. If the disconnect switch is installed in series with a circuit breaker or automatic circuit recloser, inspect the position of the series device to be sure that it is open before operating the disconnect switch. The indicating lamp or targets on the switchboard should not be relied upon for positive indication that a circuit breaker is open.

(b) Disconnect switches should be closed with a quick positive motion, with sufficient force to ensure full contact with the clips. Excessive force should not be exerted in the movement, as such force may break the insulators. If a disconnect switch is accidentally closed when the associated circuit breaker or other circuit interrupting device is closed, do not attempt to reopen the disconnect switch. Leave it closed, get away from it at once, and open the circuit by means of the circuit breaker or other suitable circuit interrupting device.

(c) A disconnect switch should be opened slowly so that it can be reclosed quickly, if necessary. If an operator should start to open a disconnect switch and finds that an arc of unusual severity is formed, this indicates that the circuit breaker or other circuit interrupting device is closed or that there is trouble on the circuit or equipment controlled by the disconnect switch. The operator should immediately reclose the disconnect switch, leave it closed, and open the circuit by means of a circuit breaker or other suitable circuit interrupting device before attempting to open the disconnect switch again.

(d) After operating a switch, check to see that it is fully closed and latched or fully open as intended.

(e) Do not use undue force in attempting to operate a switch. The operating mechanism is carefully designed for the switch. Any undue force applied by an extension of the operating handle, or an extra person on the operating handle or switch stick, may cause severe damage to the switch or mechanism.

(f) Power-operated switches should be operated periodically to assure that the switches, their mechanism, and control features are functioning properly. Where the circuit conditions will not permit operating the switch energized, and the circuit cannot be deenergized for this purpose, it is suggested that arrangements be made to disengage the operating mechanism to be checked (provided that this method does not adversely affect the overall adjustment).

3.5 CIRCUIT BREAKERS. A circuit breaker is a mechanical device for closing and interrupting a circuit and carrying current under both normal load and fault current conditions.

3.5.1 Purpose. One function of circuit breakers is to prevent or limit damage to circuits and apparatus during fault or overload conditions and to minimize their effect on the remainder of the system. During a fault or overload, the zone that includes the faulted or overloaded apparatus is isolated from the system. A circuit breaker is also used for circuit switching under normal conditions. A circuit breaker, when operated within its rating, is capable of closing into, of carrying, and of interrupting short-circuit current without being damaged. A circuit breaker maintains open-circuit conditions with operating voltage across its terminals.

3.5.2 Classes. There are generally two classes of circuit breakers.

3.5.2.1 Medium and High Voltage Power Circuit Breakers (rated above 1000 VAC).

3.5.2.2 Low Voltage Circuit Breakers (rated at 1000 VAC or less).

Section 5 discusses the medium and high voltage power circuit breaker. The low voltage circuit breaker, which includes the molded-case type, is discussed in Chapter 4, Section 6.

3.5.3 Application. Circuit breakers are used in distribution substations, switching stations, and generating stations for protecting and switching electrical service apparatus such as transformers, motors, generators, substation buses, and distribution feeder circuits. Circuit breakers are normally used where less expensive fuses and switches are not adequate because switching is frequent or available fault current is high.

3.5.4 Rating. Circuit breakers are rated in terms of voltage, continuous current, momentary current, and interrupting capability. In the normal operation of a circuit breaker the limitations imposed by a given breaker rating should not be exceeded; otherwise, excessive maintenance or unsatisfactory operation may be experienced.

3.5.4.1 Voltage Rating. Circuit breakers are assigned a voltage rating that designates the maximum system voltage at which the breaker is intended to be operated.

3.5.4.2 Continuous Current Rating. This is the maximum value of the continuous current which the contacts and conductors are designed to carry. It should not be exceeded, except for short periods; as in starting motors or rotary converters, or energizing cold loads. In an emergency, circuit breakers can be overloaded provided the associated protective relays do not trip the breaker.

3.5.4.3 Maximum Momentary Current Rating. This is the maximum instantaneous current for which the breaker has been designed to close and latch under fault conditions.

3.5.4.4 Interrupting Rating. Circuit breakers have an interrupting rating representing their design limitation for interrupting fault current. Associated with the interrupting rating is the circuit breaker's capability to close into, carry, and interrupt short-circuit current. The interrupting rating of a circuit breaker takes into account the value of current to be interrupted, the voltage across the circuit breaker contacts at the time of current interruption, and the standard duty cycle. The interrupting capacity is given as the maximum amperes the breaker is designed to interrupt at normal circuit volts, as a function of the ratio of system reactance to resistance at the point of fault.

3.5.5 Types of Circuit Breakers. Circuit breakers are divided into two broad classes: oilless and oil circuit breakers.

3.5.5.1 Oilless Circuit Breakers. The oilless class includes: air, magnetic-blast, compressed-air, gas-filled, and vacuum circuit breakers.

(a) In the air type, the arc is extinguished, or interrupted, in substantially static air in which the arc moves into arcing chutes containing metal or insulating fins. The metal fins break the arc into many short segments while the insulating fins stretch the arc. Both methods are effective in extinguishing the arc. A circuit breaker arc chute interruption is shown in Figure 3-12.

(b) The magnetic-blast type differs from the air type in that it uses a magnetic field to blow the arc into the arc chute which elongates and cools the arc.

(c) In the compressed-air and gas-filled types, high-pressure air or gas is forced through the arcing path to elongate the arc and increase the resistance to the fault current.

(d) In a vacuum circuit breaker the arc is drawn in a vacuum. The high dielectric strength and the rapid recovery rate of a vacuum gap makes arc extinguishing extremely fast and clean.

3.5.5.2 Oil Circuit Breakers. As an interrupting medium, oil is much better than air at room pressure. Its dielectric strength is greater and, in addition, the arc generates hydrogen gas from the oil which helps to cool the arc. The use of a small arcing chamber to build up pressure greatly increases the interrupting capacity of an oil circuit breaker. The major disadvantages of oil circuit breakers are their inherent fire hazard and their relatively high cost.

3.5.6 <u>Major Component Parts</u>. All power circuit breakers, regardless of the type and construction, have certain structural components that are designated similarly for all. Such components include contacts, bushings, and the operating mechanism. Following are brief descriptions of major components of circuit breakers and their functions.

3.5.6.1 Contacts. The contacts are the most vital part of a circuit breaker. They consist of a pair of separable members that are opened and closed by mechanical means. Normally the contact members are held together under pressure and the electric current flows from one to the other through the point or points of contact. Circuit breakers are provided with main contacts made of silver for carrying the continuous current. In addition, there is a pair of arcing contacts made out of tungsten which protect the main contacts from damage due to arcing. The arcing contacts, which close before and open after the main contacts, carry current only during the interrupting process and are easily renewable. Twice during each cycle of an alternating current the current amplitude drops to zero value and the arc is extinguished for an instant. In order to interrupt the circuit, therefore, it is only necessary to prevent reignition of the arc after the current reaches zero value. Whether or not the arc is extinguished immediately after the current is zero depends upon whether the dielectric strength of the arc gap builds up at a faster rate than the current waveform and permanently exceeds the system recovery voltage. This tends to reestablish the flow of current across the arc gap. In the case of an oil circuit breaker, the dielectric strength build up is accomplished by forcing clean oil into the arc path. In the case of a magnetic-blast circuit breaker, the arc is magnetically forced into the arc chute where it is elongated, cooled, and restricted to a point where the dielectric strength of the arc gap permanently exceeds the system recovery voltage.

3.5.6.2 Bushings. The bushing is the structure used to insulate the current-carrying parts from ground and from other live parts. It has a through conductor for carrying current from the line connection to the contacts. In many breaker designs it is also used to support the main contacts and interrupters. Bushings for oil circuit breakers are normally made of a porcelain or glass outer shell with an internal insulation material of: paper, oil, compound, ceramic materials, or a combination of these.

3.5.6.3 Housing. Circuit breakers are enclosed in some form of a housing to protect the essential parts from the environment, and also to protect personnel from live parts. Padmount housings normally enclose vacuum breakers in freestanding, tamperproof metal enclosures that have a neat appearance. A padmounted vacuum circuit breaker is shown in Figure 3-13. The two basic, most common forms of housings used are the tank and cubicle. In oil circuit breakers the tank is used to contain the oil in which the contacts and interrupters are immersed. The cubicle-type circuit breaker is one designed for use in a switchgear assembly. The switchgear cubicle is an indoor or outdoor assembly enclosed on all sides and top containing circuit breakers, buses, connections, and auxiliary devices. Design of the cubicle is such that when a circuit breaker is installed in its operating position, all operating parts are adequately insulated with a protective grounded barrier between all live parts and the operator. Cubicle-type switchgear is normally divided into the following types:

(a) A line-up of low voltage metal-enclosed air circuit breaker switchgear is shown in Figure 3-14. It consists of a front section; and a cable-entrance section. Each circuit breaker must be isolated from all other equipment. Circuit breakers may be either the fixed or draw-out type. The fixed type is rigidly mounted and has no provisions for quick removal. The draw-out type can be easily disconnected and removed from the switchgear cubicle while the bus remains energized. Vents are provided in the circuit breaker compartments for cooling and to release ionized gases that form when the circuit breaker opens to interrupt fault currents. Other sections of the switchgear must also be ventilated to allow circulation of air for cooling. Barriers between the bus compartment and the cable compartment are not required, but they may be furnished to permit connecting or disconnecting of the cables without danger of contacting the energized bus. If barriers are provided, all cable terminations should be insulated after installation, so that there will also be no danger of workmen contacting these hot terminals when making changes in the cable connections. Aside from having a weatherproof structure, outdoor metal-enclosed switchgear is similar to indoor equipment. Heaters, however, must be provided to keep the inside cubicle temperature greater than the outside temperature to prevent condensation. Indoor switchgear is usually painted a light gray, ANSI Std. 70, using lacquer or enamel. Outdoor switchgear is usually painted the same color inside, but the outside is painted a dark gray, ANSI Std. 24. Epoxy paints may be necessary where corrosive atmospheres exist and special protection is required. Outdoor switchgear is mounted on sill channels and the structure is undercoated with a heavy coat of an asphalt material to prevent rusting.

(b) Metal-clad switchgear may be obtained for use indoors or in weatherproof structures for outdoor use. The same comments that apply to outdoor metal-enclosed switchgear (paragraph (a) above) apply to outdoor metal-clad switchgear. Outdoor switchgear may be used to serve indoor loads when indoor space is limited, when corrosive or explosive atmospheres are present inside the building, or when the indoor atmosphere is excessively dusty. Metal-clad switchgear structures differ from the standard low-voltage switchgear structures in several respects. By definition of metal-clad switchgear the circuit breakers must be of the removable type. Circuit breakers must be enclosed, as in low-voltage switchgear, but buses, potential transformers, control power transformers and cable terminals must also be enclosed in separate metal compartments. All metal barriers must be grounded. Shutters must be provided, which close automatically when a breaker is withdrawn, to prevent operators from contacting the primary contacts or the bus which may be energized. Interlocks must also be provided to prevent moving the breaker into or out of the connected position when it is closed and to prevent closing the breaker when in an intermediate position. Instruments and relays may be mounted on the door through which the breaker is inserted into the cubicle, but when this is done, a barrier must be provided between the instruments and the breaker. Circuit breakers may be moved into the connected position in metal-clad switchgear by either the horizontal-draw-out or the vertical-lift method. When the horizontal-draw-out method is used, the breaker is moved horizontally into position in the cubicle; then a racking mechanism is provided to force the breaker into the operate position where the primary contacts are fully engaged. The secondary contacts for control of the breaker must also be in contact. A test position is also provided where the secondary contacts are separated from the primary contacts by a safe distance. Vertical-lift breakers are moved into the cubicle beneath the stationary primary contacts, then raised with either a manually or electrically operated hoist until the primary and secondary contacts are fully engaged. To connect a breaker located outside the cubicle, a plug-jumper (replacing a test position) is provided to control circuits in the switchgear for test breaker electrical operation.

3.5.6.4 Mechanism. The mechanism of a circuit breaker is the complete assembly of levers and other parts that actuates the moving contacts. The mechanism consists of two parts, the tripping mechanism and the closing mechanism.

(a) The tripping mechanism is an electrically or mechanically operated device that releases the contacts with a mousetrap like spring-driven snap action. The tripping mechanism consists of an electromagnet (trip coil) acting as a trigger that releases a latch permitting the breaker to open. The opening energy is normally supplied by accelerating springs that are charged (compressed) when the breaker is closed. All circuit breakers are equipped with a

FIGURE 3-14. LOW-VOLTAGE METAL-ENCLOSED AIR CIRCUIT BREAKER SWITCHGEAR

(REPRODUCED COURTESY OF WESTINGHOUSE ELECTRIC CORPORATION)

FIGURE NOT INCLUDED

manual trip device that is connected to the tripping linkage. Automatic tripping is normally performed by one of three methods:

- o Series-overcurrent tripping.
- o Shunt tripping.
- o Undervoltage tripping.

Series-overcurrent tripping is the tripping of a circuit breaker from a trip coil in series with the circuit responding to an increase in the circuit current above a predetermined value. Series tripping is normally used on low-voltage circuit breakers. These breakers are complete with adjustable (long-time, short-time, and instantaneous) direct-acting series overload tripping devices. Most manufacturers offer static trip units on large low-voltage air circuit breakers as an alternate to magnetic overcurrent devices. These solid-state devices are more reliable, have time-current curves with narrower performance tolerance bands, are easier to coordinate with other protective devices, and are easier to calibrate and set. Shunt tripping of a circuit breaker involves a trip coil energized from the same or a separate circuit or source of power, and controlled by contacts of a protective relay, control switch, or other means. The tripping energy for shunt tripping is either provided by a control battery or an AC control power transformer. Where AC power source is used, the most common method of tripping is the capacitor trip scheme. The AC supply is taken from the source side of the circuit breaker and the capacitor is charged before the circuit breaker is closed. To ensure adequate voltage, the capacitor is used to store tripping energy. Tripping a circuit breaker from a trip coil, responsive to a decrease in voltage below a predetermined value of circuit voltage, results in undervoltage tripping.

(b) The closing mechanism is a manually operated or power-operated device that closes and latches the moving contacts against the stationary contacts. Since the amount and speed of application of power derived directly from manual effort is limited, there are definite limitations to the size and type of circuit breakers that can be successfully operated by manual closing mechanisms. All breakers with frame sizes above 1600 A must be electrically operated. There are four general types of power-driven operating mechanisms. These are classified according to the source of energy used to actuate them, as follows:

- o A solenoid mechanism is one deriving its operating power from the electromagnetic effect of a coil on a movable part of a magnetic circuit. It can either be AC or DC actuated.
- o A pneumatic mechanism is one in which compressed air from an air receiver actuates a piston to provide the operating power.
- o A charged-spring mechanism is one deriving its operating power from energy stored in a charged spring. In most cases the spring is compressed by an electric motor. In some cases facilities are provided so that the spring can be charged by hand in case of a loss of control power.

- A hydraulic mechanism is one deriving its operating power from a fluid accumulator in which the closing energy, prestored by compressed, confined gas, is transmitted through the medium of a liquid (usually oil).

3.5.6.5 Auxiliary Relays and Meters. For both indoor and outdoor low-voltage and metal-clad switchgear the relays, meters, and control switches are normally mounted on a hinged panel attached to the circuit breaker cubicle. For outdoor oil circuit breakers the relay and meter panel is normally mounted in a weatherproof cabinet connected to the frame of the circuit breaker, or in some cases mounted in the mechanism housing.

3.5.7 <u>Operation</u>.

3.5.7.1 General Instructions. It is imperative that the operator be thoroughly familiar with equipment tagging procedures when opening circuits. In no case shall open circuit breakers, used for the control of lines, circuits, or station equipment, be considered as providing adequate protection to personnel working on the associated lines, circuits, or equipment. Isolating disconnect switches, if present, shall also be opened so there will be visible assurance that the line or.circuit is open. If the circuit breaker is a draw-out type, the circuit breaker shall be withdrawn and tagged before the circuit is considered cleared. Where no isolating disconnect switches are available or the circuit breaker is not the draw-out type, the control circuits to electrically-operated circuit breakers, which have been opened for personnel protection, must be disconnected from the control power source. This may be accomplished by removing the fuses or opening a switch in the control circuit, or by making the breaker inoperative by other means. The position of the control switch handle or the indicating lamp or targets on the switchboard should not be depended upon to determine whether the circuit breaker is open. The circuit breaker position indicator, which is mechanically connected to the operating mechanism of the circuit breaker, should be checked to give a more definite indication of the open or closed position of the circuit breaker contacts.

3.5.7.2 Electrical Control. Electrically operated circuit breakers are usually controlled from a control switch mounted on a switchboard, control desk, relay and instrument panel associated with metal-clad switchgear, or relay and instrument panel located in a cabinet mounted on the circuit breaker frame. All circuit breaker control switches have a hole in the nameplate for a red and green target indicator to show the last manual operation of the switch. In the trip position, the green signal lamp circuit can be opened by pulling the handle forward. The handle can be latched in this position and when so latched the blackout of the lamps indicates that the circuit controlled by the breaker is not in use. Indicating lamps are also used to indicate the circuit breaker position. A green light indicates that the breaker is open, and a red light indicates that the breaker is closed. On circuit breakers that are controlled from a DC power source, the red light is commonly wired so that it is energized through the trip coil circuit of the breaker to supervise the trip circuit and indicate that the trip coil circuit has continuity. When the breaker is closed, a dark red lamp would indicate that the lamp is burned out or that there is an opening in the trip coil circuit.

3.5.7.3 Automatic Reclosing. When a circuit breaker is provided with automatic reclosing equipment, the automatic reclosing shall be cut off (rendered inoperative) before the breaker is tripped or closed. The recloser relay can be cut off by moving the recloser cutoff switch to the off position. The automatic reclosing shall be left inoperative until the circuit breaker is again closed and has remained closed for a few seconds. The automatic reclosing can be turned on by moving the recloser cutoff switch to the on position. If a circuit breaker has opened automatically, and the automatic reclosing has operated to lock out or has failed to operate, the automatic reclosing shall be cut off before the circuit breaker is closed manually or electrically.

3.5.7.4 Manual Closing. Manually operated circuit breakers are closed by hand with a handle that is connected directly to the circuit breaker or is remotely connected to the circuit breaker through a system of levers, a bell crank, and rods. Successful operation of such breakers is dependent upon the operator applying positive unhesitating force through the entire travel of the operating handle. Even under normal load-switching conditions, slow or hesitant closing may result in excessive burning of the contacts, which may ultimately impair the breaker's ability to function properly. Some stored-energy closing mechanisms, such as a charged spring or hydraulic type, can be closed manually in case of control power failure. The spring or the hydraulic system can be charged manually to close the breaker.

3.5.7.5 Electrical Operation. The basic functional requirements of the controls of all modern circuit breakers are as follows:

(a) The circuit breaker mechanism will complete its closing operation, including automatic cutoff of the closing power, after a closing operation has been initiated, even though the operator releases the control switch before the circuit breaker is completely closed.

(b) Only one closing operation of the circuit breaker mechanism will result from each actuation of a manual control device (push button, switch), even though the circuit breaker trips while the control switch is being held in the closed position.

(c) If the control power supply is removed during an uncompleted closing operation, all control devices will be restored to the normal circuit breaker upon position. An additional operation of the control switch will be required to close the circuit breaker.

(d) When a circuit breaker is in the closed position, initiation of a closing operation will not result in an operation of the closing mechanism.

(e) When a closing operation of a circuit breaker (having a stored-energy-type operating mechanism; such as air, oil, or charged spring), cannot be completed successfully because of the absence of an adequate supply of stored energy, all actuating devices in the control circuit remain in the normal circuit breaker open position (when the initiating control device is operated and the breaker will not operate).

(f) A manually operated control disconnect device is provided with all circuit breakers. When opened, this device will prevent the electrical closing of the circuit breaker; both remotely and locally.

3.5.7.6 Malfunction. There are many things that can be the cause of a circuit breaker not performing correctly. Problems that can be corrected by the operator are indicated in Table 3-1 (Troubleshooting Chart for Circuit Breaker Operation). The maintenance crew is, however, responsible to remedy many circuit breaker malfunctions.

TABLE 3-1

TROUBLESHOOTING CHART FOR CIRCUIT BREAKER OPERATION

Trouble	Probable Cause	Course of Action
Failure to trip.	o Mechanism binding or sticking - caused by:	
	Lack of lubrication.	Lubricate mechanism.
	Mechanism out of adjustment.	Adjust all mechanical devices, such as toggles, stops, buffers, opening springs, etc., according to instruction book.
	o Failure of latching latch.	Examine surface of device. If worn or corroded, it should be replaced. Check latch "wipe", and adjust according to instruction book.

TABLE 3-1 ... (continued)
TROUBLESHOOTING CHART FOR CIRCUIT BREAKER OPERATION

Trouble	Probable Cause	Course of Action
	o Blown fuse in control circuit.	Replace blown fuse.
	o Loose or broken wire in trip circuit.	Repair faulty wiring. See that all binding screws are torqued to manufacturer's or U.L. specifications.
	o Dirty contacts on tripping device (Control switch, protective relays, or auxiliary switch).	Clean dirty contacts.
	o Failure of control power.	Investigate.
Failure to close.	o Blown fuse in control circuit.	Replace blown fuse.
	o Loose or broken wire in trip circuit.	Repair faulty wiring. See that all connections torqued to manufacturer's or U.L. specifications.
	o Dirty contacts on tripping device (Control switch or auxiliary switch).	Clean dirty contacts.
Failure to close.	o Failure of control power.	Investigate.
	o Insufficient air pressure.	Investigate.
Unnecessary tripping (that is tripping when tripping should not occur).	o Setting of relays or calibration setting of direct tripping device too low.	Set relay or device for proper value according to ampere load of circuit.

3.5.8 Operating Condition of Breaker.

3.5.8.1 Condition of Circuit Breaker During Interrupting Operation. An oil circuit breaker should perform at, or within, its interrupting rating without emitting flame and without releasing oil (except for minimum quantities through vent openings). Oilless circuit breakers (including compressed-air circuit breakers and magnetic air circuit breakers) should perform, at or within, their respective interrupting ratings without emitting injurious flame. The generally accepted duty cycle is two close-open operations at 15 second intervals.

3.5.8.2 Condition of Circuit Breaker Following Interrupting Performance. After completing an interruption, the components of the circuit breaker should be in essentially the same mechanical condition as prior to the interruption.

3.6 AUTOMATIC CIRCUIT RECLOSERS. An automatic circuit recloser is a self-contained protective device that automatically interrupts and recloses alternating current circuits with predetermined sequences of opening and reclosing, followed by resetting or lockout. Unlike fuse links, which interrupt either temporary or permanent faults indiscriminately, reclosers give temporary faults repeated chances to clear themselves or to be cleared by a subordinate protective device. If the fault is not cleared, the recloser recognizes it as permanent and operates to lock out.

3.6.1 Purpose. Reclosers are installed to maintain power to distribution loads with a minimum of outages. Reclosers instantly clear and reclose a circuit subjected to: a temporary fault due to lightning, trees, or similar causes; or by removing a permanently faulted circuit from the system.

3.6.2 Application. Automatic circuit reclosers are used in distribution substations and on branch feeders that are vulnerable to temporary short circuits (such as bare overhead conductor systems) to protect and switch feeder circuits. Their proper application requires a study of the load characteristics of both the protecting and the protected equipment. This includes the medium-voltage fuses or other protection in the supply to a substation; circuit breakers or reclosers at the distribution voltage supplying the feeders originating at the substation; various line reclosers, sectionalizers or fuses; and the conductors of the system.

3.6.3 Ratings. Automatic circuit reclosers are rated in terms of voltage, continuous current, minimum trip current and interrupting current. In operating a recloser, the limitations imposed by a given recloser rating must not be exceeded in any respect; otherwise, excessive maintenance or unsatisfactory operation may be experienced.

3.6.3.1 Voltage Rating. Nominal voltage specifies the nominal system voltage at which the recloser can be applied. Maximum design voltage indicates the highest voltage at which the recloser is designed to operate. Voltage ratings of automatic circuit reclosers range from 14.4 kV to 69 kV for oil reclosers and from 14.4 kV to 34.5 kV for vacuum reclosers (per ANSI C37.60-1981). Units rated 14.4 kV may be applied at any system voltage from 2.4 - 14.4 kV, as long as the proper interrupting ratings are used. Older units, that carry nominal voltage ratings below 14.4 kV (i.e., 2.4 kV or 4.16 kV), may still be in service.

3.6.3.2 Continuous Current Rating. The continuous current rating is the magnitude of rms current in amperes that the recloser is designed to carry continuously. In many cases the continuous current rating is limited by the series solenoid coil rating. As load current requirements change, therefore, it is necessary to replace the solenoid coil with one having the required rating. The continuous current ratings of automatic circuit reclosers range from 5 to 1120 A.

3.6.3.3 Minimum Trip Current Rating. The minimum trip current rating is the minimum current at which a recloser will operate. The pickup is adjustable, but generally a setting of 140 or 200 percent of the continuous current rating is used. The differential between minimum trip and continuous current ratings normally provides sufficient margin for inrush current pickup after an extended outage on a feeder circuit.

3.6.3.4 Interrupting Current Rating. The interrupting current rating is the maximum rms symmetrical current that a recloser is designed to interrupt under the standard operating duty, circuit voltage, and specified circuit constants.

3.6.4 Three-Phase Versus Single-Phase Reclosers. Automatic oil circuit reclosers are available in both single-phase and three-phase (Figure 3-15). The application of reclosers is dependent upon the type of loads being served. Three-phase equipment should not be served by a feeder using single-phase reclosers. Operation and lockout of one of the reclosers would cause single-phase operation of the three-phase equipment and result in possible damage. A three-phase recloser for such an application would disconnect all three phases regardless of which phase is faulted.

3.6.5 Construction. An automatic circuit recloser is made up of five major components: housing, bushings, mechanism, interrupter, and controls.

3.6.5.1 Housing. A vacuum recloser may be housed in a pad-mounted metal enclosure. These enclosures are easy to install, are tamperproof, and are neat in appearance. A tank is used to house the interrupter and the tripping and closing coils of an oil-filled recloser. The tank is usually made of steel and is rectangular for a three-phase recloser and cylindrical for a single-phase unit. Typical single-phase automatic recloser construction is shown in Figure 3-16.

3.6.5.2 Bushings. The bushings are the insulating structures including through-conductors with provision for mounting on the top of the recloser.

3.6.5.3 Operating Mechanism. The operating mechanism of an automatic circuit recloser provides the power to open, close, or lock out the main contacts.

(a) The tripping mechanism releases the holding means and permits the contacts to open. In most cases the opening force is furnished by springs that are charged by the closing action.

(b) The closing mechanism is normally a solenoid coil or a motor and gear arrangement. The closing force serves to close the main contacts and at the same time to charge the spring providing the opening force. The lockout mechanism locks the main contacts in the open position following the completion of a predetermined sequence of operation; i.e., when the fault is not cleared after a predetermined number of reclosures.

3.6.5.4 Interrupter. The interrupter contains separable contacts that operate within an oil or vacuum chamber. Low-energy arc interruption in a vacuum results in quiet and reliable operation.

3.6.5.5 Control. Reclosers are provided with sequence control devices and an operation integrator to change the recloser from instantaneous operations to time-delay operations, and to lock out the recloser after a prescribed number of operations. Individual tripping operations of a recloser can be made to follow instantaneous or time-delay time-current characteristics.

(a) Examples of operational sequences:

- Four time-delay operations. This consists of three open-close operations and a final open operation. All operations are preceded by a fixed time delay to allow the fault to clear. After three open-close operations, it is assumed that the fault is permanent and the fourth operation is a lockout trip.

- One instantaneous operation followed by three time-delay operations. This consists of three open-close operations and a final open operation. The first operation is instantaneous, and the subsequent three operations are preceded by a fixed time delay. The fault may be intermittent, so that the first operation, which is instantaneous, often clears the fault in a shorter time than if a time delay were used for the first operation.

- Two instantaneous operations followed by two time-delay operations. These are similar to the above, in that the first two operations are made with no intentional time delay. This is based on the assumption that most faults are transient in nature, and that possibly the fault did not clear on the first try, but no intentional time delay is needed for the second operation.

(b) Two major categories of sequence control devices:

- o In the hydraulic type, a pump piston attached to the recloser plunger raises the trip piston a certain amount by pumping a measured amount of oil under the trip piston with each operation of the recloser. This changes the sequence from fast to delayed tripping and eventually locks the recloser out.

- o In the electronic control scheme, minimum phase and ground trip values and timing of tripping, reclosing, and resetting are established by a plug-in resistance-capacitance network. Current transformers provide sensing for overcurrent or faults. The battery-powered electronic control panel sends signals to a solenoid to open or reclose the contacts.

3.6.6 Automatic Operation. When an overcurrent of sufficient magnitude flows through the trip coil or current transformers, the tripping action is initiated and the contacts are opened. The recloser contacts then reclose following a predetermined length of time. By the time the recloser has reclosed the circuit, the sequence control device has moved to count the trip operation. If the fault still persists on the circuit when the recloser closes, the tripping and reclosing sequence is repeated (a predetermined number of times), as established by the sequence control device, until the recloser goes to lockout. If the fault has cleared from the circuit during any open period, the recloser closes and remains closed, and the sequence control device resets so that it is in position for the next sequence of operations.

3.6.7 Manual Operation.

3.6.7.1 Manual Tripping. An automatic circuit recloser can be tripped open manually by moving the manual operating handle to the trip position by means of a hookstick. If the recloser is provided with a nonreclosing lever, it should be pulled down as far as possible to cut out the automatic reclosing before the recloser is manually tripped.

3.6.7.2 Manual Closing. An automatic circuit recloser can be closed manually by moving the manual operating handle to the close position by means of a hookstick or, if the recloser is provided with remote control, by moving the control switch to the close position. If the recloser is provided with a nonreclosing lever, the nonreclosing lever should be pulled down as far as it will go in order to cut out the automatic reclosing before the recloser is closed manually. After the automatic circuit recloser has been successfully closed, the automatic reclosing should be placed in service.

3.6.7.3 Manual Reclosing After Lockout Operation. Reclosers in service are designed to lock out following a selected sequence of tripping and automatic reclosing operations. When a recloser appears to be locked out, the operator is always faced with the possibility that the recloser itself may have failed. The following procedure is recommended for reclosing of recloser after a lockout operation.

(a) Locate and repair or isolate the fault.

(b) Make a careful visual inspection for evidence of housing or bushing damage, or oil leakage.

(c) Close the recloser with a hookstick, keeping the hook in the operating ring momentarily so that the recloser can be opened manually in case local trouble or failure becomes evident. If no local trouble develops, and the recloser again locks out after going through its proper sequence, it should not be reclosed again until the entire circuit on the load side has been patrolled and cleared to all sectionalizing devices.

3.6.7.4 Cold-Load Pickup. The inrush current experienced in closing a recloser after a lockout operation may occasionally introduce some complications. The highest inrush current can be from automatic starting motors or magnetizing current of transformers; however, these types of inrush currents are normally short-lived (in the order of three to thirty cycles). Some reclosers may operate on the instantaneous trip due to this inrush current, and may have to open and automatically reclose until the sequence of operation comes to the time-delay trip before the recloser will stay closed. Other reclosers, when reclosed after lockout, do not operate on the instantaneous trip. They have a time-delay trip operation to lock out, which will normally override the inrush current and pick up the load. Careful observation by the operator may indicate whether failure to hold onto the load is caused by a fault or by a momentary overload. Instant, and perhaps violent, action would indicate a fault, whereas some delay might mean overload due to inrush current. In the latter case, sectionalizing to drop part of the load, rather than a patrol, is necessary.

3.7 POWER CAPACITORS. Power capacitors are used in distribution systems to supply reactive volt-amperes (Vars) to the system. When applied to a system or circuit having a lagging power factor, several beneficial results are obtained. These results include power factor increase, voltage increase, system loss reduction, and release of electric system capacity.

3.7.1 Low Power Factor. A low system power factor can be increased by adding corrective equipment to the system. There are many devices used for power factor correction, including synchronous motors and power factor correction capacitors.

3.7.1.1 Synchronous Motors. Any synchronous motor may be used for power factor correction by overexcitation.

3.7.1.2 Power Factor Correction Capacitors. For general use, the most practical and economical power factor correction device is the capacitor. Capacitors are used at power stations where an elaborate and expensive synchronous condenser installation is not justified. The following paragraphs deal exclusively with power capacitors.

3.7.2 Ratings. Capacitors are rated in continuous kVar (kilovolt-ampere-reactive), voltage, and frequency. They are designed to give not less than rated and not more than 135 percent rated kVar when operated at rated voltage and frequency. Capacitor units are normally available in voltage ratings of 2,400 V to 34,500 V and kVar ratings from 15 kVar to 300 kVar. Various manufacturers' medium-voltage units up to 200 kVar are interchangeable. Capacitors are generally rated at a frequency of 60 Hertz (Hz), however, they are also suitable for operation at frequencies below 60 Hz. There is no physical limit to the under-frequency operation of the capacitors. The limit is economic, in that the capacitor kVar output is directly proportional to frequency and applied voltage. If a capacitor is operated at a frequency lower than rated, consequently, its kVar rating is reduced. Since capacitors are installed in theory to utilize their rated capacity, utilization at reduced frequencies is not economical, as the unit's design rating can never be achieved.

3.7.3 Construction. A capacitor unit consists of two aluminum foil strips or plates with thin high-grade insulating paper or a synthetic film placed between them. The strips or plates are compactly wound and connected in groups, each of which is connected to a terminal. There is no contact between the two metal surfaces. When these two surfaces are connected to a source of power, energy is stored in the capacitor. The capacitor remains charged at, or above, full line voltage when disconnected from the source of power until a discharge path is provided between the terminals. Capacitors have a built-in discharge resistor designed to drain off or reduce this residual charge. National Electrical Code requires capacitors rated 600 V or more to be discharged to a residual voltage of 50 V or less in 5 minutes. Since the built-in resistor has the disadvantage that it cannot be visually inspected for an open circuit, it should not be relied upon for positive drain-off of the residual charge (see subparagraph 3.7.9). The wound plates and discharge resistor of a capacitor are enclosed in a welded sheet steel or stainless steel container, which is hermetically sealed to protect the capacitor from deterioration due to entrance of foreign material or moisture. The contents are vacuum dried and are usually impregnated with a dielectric fluid. As of 1 October 1977, dielectric fluids containing polychlorinated biphenyls (PCBs) can no longer be installed. The connecting leads from the capacitor are brought up through the bushings to a joint at the top directly under the brazed terminal. The bushings supplied on capacitors are usually made of porcelain. As of 1 October 1988, existing PCB capacitors in unrestricted areas must be removed.

3.7.4 Types of Installations. The greatest electrical benefits are derived from capacitors connected directly at the loads. This would permit maximum loss reduction and released line capacity. However, economics and physical limitations are usually the governing factors. Capacitors may be divided into two classes, primary capacitors and secondary capacitors. Primary capacitors are those rated 2400 V and above and secondary capacitors are those used on the low-voltage side of distribution transformers or at motor terminals and are normally rated 600 V and below. The three most common types of power capacitor installation are: pole-mounted, metal-enclosed, and open-rack.

3.7.4.1 Pole-Mounted. Pole-mounted capacitors (Figure 3-17) are packaged as a complete unit containing all necessary items for a switched distribution capacitor bank installation. The banks consist of an aluminum or steel mounting frame that supports the capacitor units, interconnecting wiring, and capacitor switches. Overcurrent protection is usually provided by group fuses.

3.7.4.2 Metal-Enclosed. Metal-enclosed capacitor banks (Figure 3-18) consist of a factory assembled group of individual capacitor units mounted in a protective housing complete with bus connections, controls, and protective and switching equipment within the enclosure. Personnel safety and compactness are the major benefits. Each capacitor unit is normally protected by an individual current-limiting fuse.

3.7.4.3 Open-Rack. An open-rack capacitor installation (Figure 3-19) is a field-assembled group of capacitor units mounted in an open-rack structure without enclosing plates or screens. Open-rack installations are normally made up of several stack-type capacitors connected in parallel to provide desired kVar capacity. All the units in a given stacking unit are normally connected in parallel with the steel frame forming one terminal and the insulated bus forming the other. For open-rack installations the capacitor units are protected by individual fuses, group fuses or relays, and a circuit breaker.

3.7.5 Fixed Capacitors. Fixed capacitor installations are those that are continuously on-line. Fixed capacitor banks are connected to the system through a disconnecting device that is capable of interrupting the capacitor current, allowing removal of the capacitors for maintenance purposes. Fixed capacitor banks should be applied to give a voltage boost to the system during heavy load periods. Caution must be used, however, to ensure the boost will not be excessive during light-load conditions. To isolate or deenergize a fixed capacitor installation, the disconnecting switches should be opened with rapid positive action. The successful switching of capacitors depends, to a considerable extent, on the technique of the operator and the speed of opening. It is more difficult to deenergize a capacitor bank than it is to energize it, because the ease with which capacitor current is interrupted depends on the point on the voltage wave when the switch contacts separate. If the arc is reestablished and maintained with the disconnecting device open, the switch should be reclosed at once to avoid damage to the switch. Another attempt should then be made to open the disconnecting device. After the disconnecting device has been opened, the capacitor installation is isolated but still charged. The capacitors should be left open from the line for at least five minutes before they are returned to service. This precaution will prevent a buildup of the line voltage above normal, which may occur if a fully charged capacitor bank was closed on a line.

3.7.6 Switched Capacitors. Switched capacitor installations are those where the capacitor bank is switched in and out of service depending upon system operating conditions. They are usually switched on when the load requirements are the greatest and switched off during light-load conditions. Sometimes the capacitor banks are installed to enable incremental switching, depending on the system reactive requirements and the amount of system voltage required. To remove a switched capacitor bank from service, the control box should be opened and the automatic control lever or control switch should be placed in the off position. The circuit breaker or the switching device should then be tripped. To ensure the circuit breaker or switching device remains open, the fuses should be removed from the control circuit. Before it can be assumed that the capacitor bank has been deenergized, the position of the switching device should be inspected. On a circuit breaker, the position indicator should be checked. For oil switches, the position of the operating handle can be checked with a switch stick.

3.7.7 Types of Switching Devices. Switching capacitors imposes severe duty on switching devices because of the differences in phase relationship between the current and voltage on a capacitor circuit. When a capacitor bank is energized, high transient overvoltages and high-frequency transient inrush currents may be produced. The magnitude of the transient overvoltages may easily be three times the rated line voltage, and transient inrush currents may approach the short-circuit current duty values. These factors are especially important when one or more capacitor banks is already energized and another one at the same location is switched on to the bus. The methods for determining the values of inrush current, transient overvoltage and resonant frequency of the circuit are discussed in more detail in ANSI C37.99, IEEE Guide for Protection of Shunt Capacitor Banks, and ANSI C37.012, Application Guide for Capacitance Current Switching of AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.

Switching devices, as discussed below, have a separate capacitive switching rating for the reasons mentioned above, and the switching rating of the device must be at least 135 percent of the capacitor bank rating to which the switching device is connected. This rating is a minimum specified by the National Electric Code, and includes allowances for operation at overvoltage, allowance for capacitance manufacturing tolerance, and allowance for harmonic components above the fundamental frequency. Some common types of switching devices used on capacitor banks are discussed in the following paragraphs.

3.7.7.1 Indoor Circuit Breakers. Metal-enclosed capacitor equipment on circuits 13.8 kV, or below, often use indoor air or oil circuit breakers. These breakers are housed in a separate compartment to protect them from the weather and to increase operating personnel safety.

3.7.7.2 Outdoor Circuit Breakers. On large open-rack outdoor installations, outdoor oil circuit breakers are usually used. In some cases, the interrupting chambers of these breakers is modified to ensure proper switching of the capacitive load by controlling prestrikes when energizing or restrikes when interrupting.

3.7.7.3 Oil Switches. Single-phase or three-phase oil switches are often used on pole-mounted or metal-enclosed capacitor banks. These switches are generally solenoid or motor-operated and do not have fault interrupting capability.

3.7.7.4 Load Interrupter Switches. A load interrupter switch is employed for capacitor switching. The most common types are air, gas-filled, and vacuum switches. These devices do not provide fault protection and are backed up by fuses or circuit breakers.

3.7.7.5 Fused Cutouts. On small fixed installations, fused cutouts are sometimes used to perform the switching operation.

3.7.8 Control Devices. Switched capacitor bank control systems initiate the switching of the capacitors into, or out of, the circuit at predetermined conditions. The auxiliary components of the controls include sensors, circuit breakers or switches, and the control power source. The controls normally include an automatic control lever or control switch that permits the operation of each capacitor switch either by manual operation of its control switch or in response to a signal initiated by a sensor. The most commonly used inputs for capacitor bank control are time, voltage, current, and load kVar.

3.7.8.1 Time Switch Control. Time switch or time clock control is often used with small switched capacitor banks. Time control switches the capacitor bank on at a certain time of the day and off at a later time. A carry-over device is normally used for each time clock to keep the clock running during temporary power outages. If a carry-over device is not used, it will be necessary for the operator to go to each capacitor location that is affected and reset the clock after a power outage.

3.7.8.2 Voltage Control. Voltage control is widely used for capacitor switching in substation applications. It is generally used to correct steady-state undervoltage conditions caused by heavy circuit loading, or inadequate voltage regulation from upstream transformers and line regulators. Voltage control includes a voltage-sensitive relay, and time-delay and auxiliary relays to open and close the capacitor switching device in response to predetermined values of steady-state circuit voltage. The time-delay relay is incorporated so that the switching operation is not initiated for momentary line voltage dips, that may be caused by a lightning strike, a momentary dip caused by a line fault, or by a large motor load starting on a downstream bus.

3.7.8.3 Current Control. Current control is often used on regulated circuits where voltage cannot be used for capacitor switching. Voltage control includes a current-sensitive relay plus time-delay and auxiliary relays to open and close the capacitor switching device in response to predetermined values of load current.

3.7.8.4 Kilovar Control. The capacitor bank will be energized at a certain value of lagging power factor. It will be switched off at a lower value or when there is leading power factor. Kilovar control is used to reduce peak kVar loads.

3.7.8.5 Combined Controls. Combined controls can be used for more complex situations.

For example, kVar control can be used to maintain a power factor value and voltage control can be incorporated as an override to remove the bank under abnormal voltage conditions.

3.7.9 Service Conditions. The life of a capacitor unit is shortened by overvoltage, overheating, chemical change, physical damage, and repeated temperature changes.

3.7.9.1 Operating and Ambient Temperatures. Capacitor units are suitable for continuous operation with an ambient temperature range of -40°C to +46°C. When ambient air temperatures higher than 46°C are expected, forced circulation of air may be used. Normally, the maximum surface temperature of an individual capacitor unit is used to indicate the operating-temperature condition. The temperature (at any point on the case), generally should not exceed 55°C (131°F) under usual operating conditions or 70°C (158°F) under emergency operating conditions. Capacitor units may be operated continuously at ambient temperatures as low as -40°C. When energizing capacitors after they have been deenergized for a period of time, the temperature of the capacitor unit should be considered. There is a risk of damage to capacitor units if they are energized at temperatures less than -20°C.

3.7.9.2 Operating Voltage. Capacitors cause a voltage rise at their application point. Thus, capacitors are more likely to operate at overvoltages than equipment that causes voltage drop at its application point. The maximum permissible working voltage of power capacitors is 110 percent of rated voltage. Because the kVAR rating of a capacitor varies as does the square of the ratio of the applied voltage to the rated voltage, applied voltage must be nominally limited to rated voltage. Operation of capacitors above rated voltage increases capacitor kVAR, which further increases the voltage level. Under emergency conditions, however, capacitors may be operated above 110 percent of rated voltage. The recommended maximum rms overvoltage without loss of capacitor life is dependent on the duration of each overvoltage. Table 3-2 lists the recommended limits of overvoltage, expressed as a percent of rated voltage, versus the time duration of the overvoltage condition. For example, a capacitor could be applied at 2.2 times rated voltage for a period of one second without incurring any loss of usable life. The recommended overvoltage limits are listed in Table 3-2.

Large capacitor banks are usually protected by fuses located (or installed) at each capacitor. Fusing provides each capacitor with proper protection and also allows partial operation of the bank when an individual capacitor fails. The fuse also serves to indicate unit failure. When a large shunt capacitor bank is made up of series-connected groups of parallel units, the removal of one or more units from a group will cause overvoltages on the remaining units. The failure rate of capacitor units increases rapidly when subjected to overvoltage. Some type of protection is, therefore, normally installed on large banks. This protection disconnects the bank from the system or sounds an alarm when a significant number of units have been removed from service. There are several schemes used to provide this protection. Most schemes require potential or current transformers on the capacitor bank neutral.

TABLE 3-2
OVERVOLTAGE LIMITS

Duration	Multiplying Factor Times Rated rms Voltage
1/2 cycle	4.8
1 cycle	4.2
6 cycles	3.0
15 cycles	2.6
1 second	2.2
15 seconds	1.8
1 minute	1.7
5 minutes	1.5
30 minutes	1.35

3.7.9.3 Overload Current. Abnormal capacitor currents due to resonance may occasionally be encountered. Blowing of fuses or high-temperature operation may indicate an overload condition. Capacitors and auxiliary devices are normally designed to carry at least 135 percent rated kVar maximum including kVar due to resonance. If the capacitor kVar exceeds 135 percent of its rating, it should be reported.

3.7.10 Personnel Protection. Operators, working on capacitors or other equipment to which capacitors are connected, should wear rubber gloves and safety glasses or a face shield for protection from arcing. Such work includes opening or closing switches or fused cutouts, testing, short-circuiting terminals, and grounding capacitor terminals to the case or rack. When the area around capacitors and other electrical apparatus is wet, wood platforms, insulated stools, or rubber boots should be used. After disconnecting a capacitor, and before any work is attempted, the operator should wait at least five minutes to allow time for the resistors to drain off the major portion of the residual charge. The capacitors should then be short-circuited several times or until no arc is observed. An insulated jumper should be used for short-circuiting. Each terminal should then be grounded. The short-circuiting device and ground connection should be left in place until the work is finished, but must be removed from the capacitor before the unit is reenergized.

3.8 DISTRIBUTION SUBSTATION. Each distribution substation normally serves a single load area. At the distribution substation the subtransmission voltage is reduced for general distribution throughout the area. The substation consists of one or more power-transformer banks together with the necessary voltage regulating equipment, buses, and switchgear.

3.8.1 Substation Grounding. In the past, substation grounding has been taken for granted and has even been ignored. The large growth of the electrical system and the number of interconnections with the power suppliers increase the ground fault current and the probability of electric shock when substation equipment is not grounded.

Utilization of sound engineering principles is required for acceptable substation grounding providing a safe and shockproof grid around the substation. The old practice of installing just a few conductors for a substation grid around the substation transformer is no longer acceptable.

The four steps presented on the following pages (soil resistivity test, maximum ground fault current, design of grid, and measurement of soil resistivity) are all necessary functions to ensure safety around the substation.

3.8.1.1 Soil Resistivity Test. Preliminary designs of substations should include an investigation of the general soil type to aid in foundations design. Any such investigation will indicate a rough approximation of the soil resistivity similar to the typical values shown in Table 3-3. Testing soil samples in the lab, the three pin method, and the four pin method are three procedures used to determine soil resistivity in the substation lot.

3.8.1.2 Maximum Ground Fault Current. The value of maximum ground fault current must be calculated for use in the substation ground design. An allowance for future growth should be made, and an adjustment should also be made for the effect of direct current offset and attenuation of alternating current and direct current transient components of fault current.

3.8.1.3 Grid Design. The preliminary design of the station grounding should consist of placing and noting of all the required grounding. The following is a list of the grounding requirements normally found in substations.

(a) Power transformers require two grounds, each capable of carrying full fault current.

(b) Lightning arresters require one ground connected from the grid directly to the lightning arrester base. The ground must be capable of carrying the discharge.

(c) Dead-end towers normally require one ground per each leg connected to the structure.

(d) The following items or structures require a minimum of one ground per each leg:

- Switch Stand.
- Bus Support Structures.
- Potential and Current Transformers.
- Coupling Capacitors.
- All Miscellaneous Structures.

TABLE 3-3
EXPECTED SOIL RESISTIVITIES

	Resistivity			
	OHM-Centimeters		OHM-Meters	
Soil Types	Minimum	Maximum	Minimum	Maximum
Clay, Moist	1,400	3,000	14	30
Swampy Ground	1,000	10,000	10	100
Humus and Loam	3,000	5,000	30	50
Sand Below Ground-Water Level	6,000	13,000	60	130
Sandstone	12,000	7,000,000	120	70,000
Dry Sand	20,000	7,000,000	200	70,000
Broken Stone Mixed with Loam	20,000	35,000	200	350
Limestone	20,000	400,000	200	4,000
Dry Earth	100,000	400,000	1,000	4,000
Dense Rock		1,000,000		10,000
Crushed Rock	300,000	400,000	3,000	4,000

(e) Oil circuit breakers require two grounds.

(f) Station fences require complete perimeter ground cables, located three feet outside the fences, and are connected to the station grid. Ground spacing should not exceed 75 feet. Fences require a fabric ground for approximately every 75 feet and a post ground for every third post.

(g) All station gates require connection to both gate posts and copper braid to connect the hinge posts to the gate.

3.8.1.4 Measurement of Soil Resistivity. An earth resistivity measurement of the soil is important and should be carried out upon installation of the ground grid to assure accuracy of the grid placement and to assure no loose ends or bad connections exist. The most common method used to measure the soil resistivity is the four pin method.

3.8.2 Cable Placement. After the above ground connections are completed, the underground cable, connecting cable, and ground rods should be placed. Cables should be laid in parallel lines with reasonable spacing to connect these points. Ground rods should be placed at crossings and should be as close as possible to transformers, lightning arresters, and ground switches, but should not be spaced closer than ten feet. Cables shall be sized accordingly:

(a) Able to resist fusing and deterioration of electric joints for the worst case fault current magnitude and duration possible.

(b) Mechanically rigged to a high degree. Normally 1/0 is adequate, mechanically, for brazed joints and 2/0 for bolted joints.

(c) Have sufficient conductivity to prevent contribution to dangerous local potential differences.

3.8.3 Preventive Maintenance. Proper maintenance of line and substation equipment will reduce both unnecessary outages and operating costs. Preventive maintenance is also less costly than maintenance that must be performed on already damaged or faulty units. Procedures for maintaining the following apparatus are discussed in detail below:

3.8.3.1 Transformers. Transformer maintenance procedures may be divided into the following service classifications:

(a) Distribution Transformers:

- Check all the overhead connections monthly.
- Check the oil content for PCB contamination annually.
- Check oil level annually.
- Check the bushings for cracks or loose contacts annually.
- Obtain oil sample and perform lab tests for dielectric strength, neutralization number, interfacial tension, and gas-in-oil analysis every two years.

(b) Substation Transformers:

- Check all the overhead connections monthly.
- Check the oil content for PCB contamination annually.
- Obtain oil sample and perform lab tests for dielectric strength, neutralization number, interfacial tension, and gas-in-oil analysis annually. For arc furnace, rectifier, and on-load-tap changer type units, the frequency should be from quarterly to annually, depending on the service and history of the individual unit.
- Check the bushings for cracks or loose contacts annually.
- Check the connections of incoming and outgoing overhead/underground conductors at the bushings biannually.
- Check the service transformer connection annually.
- Check the fuses on the high side and the low side annually.

- o Check the current and potential transformers and the disconnect switches for manual operation annually.
- o Check the transformer tank, cooling fins, tubes, radiators, and all gasketed and other openings visually for any possible leaks monthly.
- o Check the gauges on the transformer for oil level, oil temperature, and tank pressure weekly. Look for signs of overheating or corrosion.
- o Observe any change in operating sound regularly. A louder hum than normal could indicate low oil level or temperature rise inside the tank.

(c) Dry Type Transformers:

- o Retorque connections, vacuum out dirt, and blow with a maximum of 25 psi compressed air every two years.
- o Check temperature and cleanliness weekly. Look for signs of overheating or corrosion.

3.8.3.2 Voltage Regulators. The following represents a maintenance checklist for voltage regulators. Each item should be spot checked on a periodic basis to ensure proper function:

(a) Check for physical damage to the tank periodically.

(b) Check the connections.

(c) Check the operation lever setting for boosting and bucking voltage.

(d) Check the accuracy of the regulator by checking the voltage across the bus with the help of a voltmeter.

3.8.3.3 Switches. There are several different types of switches on line and on the substation busses. The primary function of a switch is to open or close a feeder.

(a) Check for loose connections and proper operation biannually.

(b) Check contact surfaces biannually.

3.8.3.4 Circuit Breakers. The following represents a maintenance checklist for low voltage and high voltage circuit breakers. Each item should be checked every three years for low voltage circuit breakers, every two years for high voltage circuit breakers, and annually for high voltage circuit breakers used in generating stations.

(a) Check mechanical and electrical operation and alignment.

(b) Check condition of contacts and measure the contact resistance.

(c) Check and tighten the connections.

3.8.3.5 Reclosers.

(a) Check the reclosing capabilities annually.

(b) Check and replace oil in the tank at least biannually.

(c) Check the physical condition of the tank periodically.

(d) Check the tripping coils for proper function, periodically.

3.8.3.6 Power Capacitors. Capacitors are usually maintenance free, although routine checks will extend service life.

(a) Check the connections visually with regard to the conductor and service transformers.

(b) Check for PCB contamination annually by checking the dielectric strength.

(c) Check the tank for damage.

(d) Visually check the rack for corrosion.

(e) Manually test control operation annually.