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IEEE Design Guide for Electric Power Service Systems for Generating Stations

Sponsor

**Energy Development and Power Generation Committee
of the
IEEE Power Engineering Society**

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Abstract: This guide applies to station service systems that supply electric power to auxiliary loads for electric power generating stations. The discussions and recommendations contained herein provide the practices, criteria, and range of system parameters that relate to the service system requirements and assist in the application of existing engineering documents. This guide is not a handbook of design data; however, it explains what is good practice for the many different types of electric power service systems for generating stations.

Keywords: auxiliary systems, cable, motor, relay, short circuit, transformer, voltage

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Foreword

(This foreword is not a part of IEEE Std 666-1991, IEEE Design Guide for Electric Power Service Systems for Generating Stations.)

This document is primarily tutorial in nature as it is intended to provide guidance and direction in the design of electric power service systems for electric power generation plants. The guidance and direction given in this document is, for the most part, general in nature, and is applicable to all types and sizes of electric power generating plants.

This guide does not provide unique and specific design direction and guidance for special systems in the various types of electric power generating plants, but rather provides the basic framework upon which any required unique and specific designs can be built. An electric power service system consists of a main auxiliary power distribution network, which may supply many subsystems such as electric trace heating systems, dc systems, Class 1E power systems, etc. It is recommended that the reader consult industry standards that address these specific subsystems in more detail as appropriate during the design process.

This design guide was prepared by the Auxiliaries Systems Working Group of the Station Design Subcommittee of the Energy Development and Power Generation Committee of the IEEE Power Engineering Society.

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IEEE Design Guide for Electric Power Service Systems for Generating Stations

1. Introduction

This design guide applies to station service systems that supply electric power to auxiliaries for generating stations that produce electric power.

There are numerous industry standards, regulations, and guides for equipment and components of these systems. The discussions and recommendations contained herein provide the practices, criteria, and range of system parameters that relate to the service system requirements and assist in the application of the existing engineering documents.

This design guide is not a handbook of design data, but it explains what is good practice for the many different types of electric power service systems for generating stations. It is anticipated that this guide will assist those who must establish the criteria for the design of generating station auxiliaries and their electric power service.

2. Scope

While this design guide applies to all types of power generating stations, it is particularly applicable to stations in which the electric power service system is required to perform continuously. When electric power for auxiliaries is supplied from the power grid, the service system begins at the point where the tap from the power grid terminates, either at a station service bus or at the terminals of the transformer that supplies the bus.

When service to auxiliaries is from independent generators or electric storage batteries that are not normally operated as power supplies to the power grid, the station service system includes the generators and storage batteries. The service system includes all of the electric power using devices it serves, such as motors, resistance heaters, rectifiers, etc.

This guide contains a listing of typical power plant auxiliaries and criteria for their power service and examples of single-line diagrams for a typical plant. It also includes tables of typical power service parameters to illustrate the range of typical values for each parameter, and it identifies the approximate effect of the minimum and maximum value of each parameter on the load. Each section, as appropriate, has a bibliography of industry codes and standards and other reference documents that provide detailed guidance in the design and specification of station service system components.

3. System Philosophy

3.1 Introduction

An electric power generating station can only produce power if its auxiliaries are functioning. Upon loss of supply power to these auxiliaries, a unit may be idled or damaged. The electric power supply system for auxiliaries generally costs less than 5% to 10% of the total plant cost. Additional costs incurred during a long-term outage due to nonproductive investment, repair of major equipment, and incremental cost of replacement power can exceed the total cost of the auxiliaries system.

Power system engineers who plan and design an auxiliaries system must be aware of the need for a well planned, well engineered, and reliable auxiliaries system. They must consider a wide range of technical points during the planning process while using operating experiences and field reports, either acquired personally or by those who will eventually operate the system, to ensure that all possible aspects of the design have received attention. In this section, basic design considerations (see 3.2), a general planning guide (see 3.3), and transmission system and main generation considerations (see 3.4) are presented to assist the engineer in planning and designing the auxiliaries system.

This section is devoted to the more basic and general philosophies that must be addressed in the design of an electric power service system. Expansion on these philosophies is undertaken in subsequent sections that provide more detailed guidance on issues such as

- 1) Typical power plant auxiliary loads and their power service requirements
- 2) Typical power service parameters including how and why they must be considered
- 3) Typical power service components and their design requirements
- 4) Typical power system design requirements and limitations

3.2 Basic Design Considerations

Many factors are considered in the overall planning and design of an auxiliaries system for a generating station. These factors influence the design and operation of a unit and may be stated as design criteria. Some of the factors are discussed in the following paragraphs. Where appropriate, examples of design criteria are given. It should be noted that some of the criteria overlap. A safety criterion, for example, may also be an equipment application criterion. Thus, the example criteria given may be classified differently by different designers. In all cases, a number of criteria should be developed. The criteria given below are merely examples and are not intended to be all inclusive.

3.2.1 Safety

Safety is of primary importance in the design of an auxiliaries power supply system. Industry standards and codes for equipment capabilities should be met. Whereas the safety and design life of the equipment may be compromised under certain conditions, the possibility of harm to plant personnel and the public must be considered and avoided.

Safety considerations are implemented by establishing criteria such as

- 1) When all generating units are out of service, power is to be maintained for lighting, communication, heating, ventilation, control power, elevators, lubrication, plant security, and like loads for safe shutdown of the unit under normal and emergency conditions. This may be done by uninterruptible power systems or other alternate ac or dc sources, depending upon the criticalness and nature of the load.
- 2) Power supplies and critical loads should be divided between unit auxiliaries buses so that the failure of any one bus or power supply will not prevent the safe shutdown of the unit.
- 3) All electrical equipment enclosures should be permanently grounded by direct connection to the station grounding system.

3.2.2 Reliability

Since the unit will not function without adequate auxiliaries, the reliability of the auxiliaries system directly effects plant performance. Interruptions that reduce the output of a unit, either partially or completely, should be avoided where possible. The system should be designed so that reserve capacity and alternative power supplies minimize the effects of service component outage. System design should minimize the effects of service component failures or malfunctions on the uninterrupted portion of the system.

The following are examples of possible reliability design criteria:

- 1) The failure of one start-up source should not prevent any unit from being started or shut down.
- 2) Any unit should be able to carry a full load with one of its unit auxiliaries transformers out of service.

The reliability of the auxiliaries power supply system should be consistent with the importance of the unit to the power system, industry codes and standards, and regulatory requirements.

3.2.3 Cost

Capital operating and maintenance costs of the auxiliaries power supply system and associated equipment are key factors in the design. Costs for installation, operation, expandability, and maintenance should be evaluated over the life of the equipment as part of determining the total cost of each plan. Although the worth of expandability and future capability of the system is usually difficult to quantify, it is very important because future load additions may require expensive modifications that may be avoided or minimized by considering them properly in the initial design.

3.2.4 Operation

Auxiliaries power-supply systems that are flexible and simple to operate can contribute greatly to system reliability. Direct radial systems are simple. However, designing for additional reliability can suggest interconnecting buses or providing ties between buses. Interconnecting auxiliaries buses usually results in a complex switching scheme that may be difficult or expensive to protect. Ties between buses may result in switching errors that cause equipment damage or unit trips.

Since designing for additional reliability often results in a more complex system, the operation of these systems must be considered to determine the true increase in reliability.

Some examples of operating criteria for reliable designs are

- 1) The unit will normally provide power for its auxiliaries through transformers connected to the generator bus.
- 2) The protective relaying will function to isolate system faults by removing a minimum number of components from service.

3.2.5 Equipment Application

Equipment selection and application within an auxiliaries system are subject to a number of industry application guides, manufacturing standards, and safety standards. To assure safe, economical, and dependable operation, the equipment should be applied in accordance with the recommendations of the appropriate guides and standards. As many of the major pieces of equipment used in the auxiliaries system are expensive, the application and protection of the equipment should be coordinated. Some examples of design criteria that apply to equipment application are

- 1) The auxiliaries power system steady state voltage regulation should not exceed industry standards.
- 2) Voltage dip when starting any large motor should not prevent the motor from starting or damage the motor. This voltage dip should not cause malfunction of energized loads, such as stalling of running motors, or cause dropout of relays or contactors.

- 3) The transformer impedances should be coordinated with the switchgear ratings. Fault currents should be determined with maximum loads, maximum transformer primary voltages, and minimum source impedances while assuming negative manufacturer's tolerances on impedances.
- 4) The horsepower rating of the motors should be coordinated with the requirements of the driven load (see Section 11.).
- 5) Any motor, NEMA frame size 440 and larger, should be capable of accelerating its load with 85% of rated motor nameplate voltage at the motor terminals (see ANSI C50.41-1982 [B2]¹). This criterion can be more restrictive than 3.2.5(2). An alternate criterion might specify that these motors be capable of accelerating their loads with less than 85% rated voltage applied, thus allowing more flexibility in specifying parameters such as transformer impedances.

3.2.6 Maintenance

The design of the auxiliaries power supply system should include provisions for preventive maintenance. The equipment should be located so that it is accessible for inspection, removal, teardown, and repair, and the work space should be well lighted, adequately ventilated, and safe for personnel. In some cases, additional power circuits or components may be desirable to provide back-up service to certain auxiliaries that permit in-service repairs without reducing unit output. This could be expressed as one of the design criteria given in 3.2.2. A cost/benefit analysis of this form of service should be made during the design of the auxiliaries power-supply system.

3.2.7 Plant Expansion

Over the life of a plant, loads may be added for environmental protection, improvements in plant efficiency, safety, reliability, and other changes in operating conditions. These future loads should be anticipated during the initial design, though their details may not be known. Some designers may choose to build as large a system as is feasible to maximize reserve capacity (i.e., transformers are sized to the maximum short-circuit and voltage-regulation limits). An alternate design would provide for future switchgear, transformers, and other equipment that might be required.

Some examples of design criteria for plant expansion are

- 1) The overall design should provide for flue gas desulfurization equipment.
- 2) The unit auxiliaries and station service transformers should have a specified reserve capability.
- 3) The unit auxiliaries and station service transformers should have provisions for future forced-cooled ratings.
- 4) A specified number of spare switchgear cubicles should be provided.
- 5) Space should be provided in the physical design for connection of future transformers to the generator and startup source overhead conductors.

Approaches may vary, but the planner is encouraged to make allowances for expansion, which, as history indicates, is inevitable.

3.3 General Planning Guide

There are many general system considerations, concepts, design principles, and operating philosophies that, if evaluated during the planning stage, can result in a more reliable, flexible, and economical auxiliaries system. Some major factors to be evaluated are discussed in 3.2. In this section, these factors are discussed in more detail as they apply specifically to auxiliaries system planning. A planning guide flow chart is presented in Fig 3.1. Many of the items included will not be applicable to particular units; however, some apply to all plants. Where experience or other factors dictate, the planning guide should be modified.

¹The numbers in brackets, when preceded by the letter "B," correspond to the Bibliography in Section 3.5.

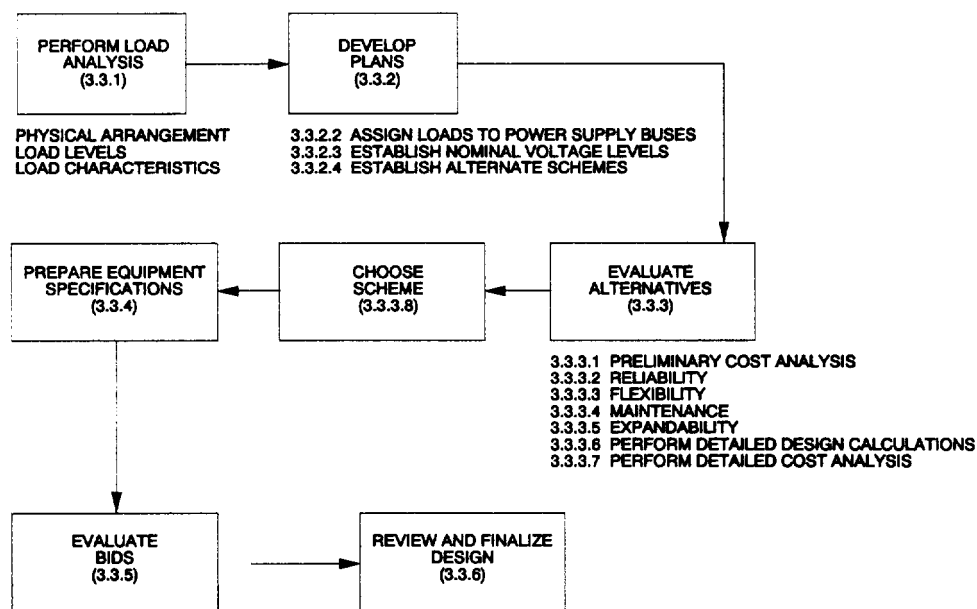


Figure 3.1 – Planning Guide Flow Chart

3.3.1 Load Analysis

An initial step in the design of a power supply system is the analysis of the auxiliaries (loads) to be served. The electrical system that serves these auxiliaries should have capacity and availability equal to their functional requirements. During the initial design stages, firm data on the auxiliaries may be difficult to obtain. In these cases, estimates based on previous designs may be used. The load analysis should evaluate the following:

- 1) *Physical Arrangement.* Data on cable lengths, special load requirements, and alternative locations for auxiliaries buses and equipment.
- 2) *Load Levels.* Data such as the horsepower, power factor, and demand factor of the load should be obtained to determine capacity ratings of power supply circuits and equipment.
- 3) *Load Characteristics.* How the loads can and will be operated can influence the auxiliaries system design (i.e., low speed start of two-speed motors, number of required switching operations, required startup loads, running and shutdown loads, variable frequency drive system harmonics, etc.).

Additional details of load analysis are presented in Section 4.

3.3.2 Development of Plans

3.3.2.1 General

All acceptable plans or schemes should be developed within the established design criteria. No one plan may completely satisfy all design criteria at a reasonable cost. An optimal plan, however, can be found. This plan should consider the following criteria as well as the design criteria.

- 1) *Operating Experience.* Examination of design and operating experience on existing plants will provide useful information in establishing acceptable plans for the auxiliaries power system. Information on the performance of past designs can be used to avoid the pitfalls of designs that have performed less than satisfactorily. Data on past operating experience can provide information on expected load demand factors,

desired bus voltage regulation (which may be more restrictive than equipment limits), special switching features, etc.

- 2) *Accepted Industry Standards.* The schemes to be evaluated should conform to accepted industry standards. This provides some correlation between the auxiliaries power system designer and the equipment manufacturer. Industry standards can be obtained from ANSI², IEEE³, NEMA⁴, and other technical or environmental organizations.

3.3.2.2 Assigning Loads to Buses

In assigning loads to buses, the following criteria apply:

- 1) Multiple loads providing the same function for a unit (e.g., multiple induced draft fans) should have separate power circuits and should be supplied from a minimum of two buses. This will enhance the possibility of being to operate the plant (even at reduced output), or minimize mechanical system transients due to the outage or trip of any one power and short-circuit or auxiliaries bus.
- 2) The thermal and short-circuit loading on buses should be balanced to the extent practical to simplify certain equipment design, to minimize the number of different equipment ratings, to reduce system losses, etc.
- 3) The large motor loads should be distributed onto multiple buses to reduce the motor contribution of fault current on any one bus. This allows better balancing of the bus fault levels. In addition, there may be economic advantages in having the larger motors on one power circuit or bus, so that lower rated switchgear can be used for the remaining power circuits and buses.
- 4) Special purpose critical loads should be served by power circuits and buses having two separate and independent power supplies. The physical location of these load feeders also influences the overall bus and load configuration to assure that the failure of any one power-supply circuit will not cause the failure of other power supply circuits.
- 5) Distribute harmonic generators, such as variable frequency drive systems, to reduce harmonic distortion on any one bus. Note that the effect of harmonic voltage and current distortion on system components (i.e., connected motors, relaying, meters, controls, generators, etc.) should also be considered.

These and other criteria are discussed in more detail in subsequent sections.

3.3.2.3 Establishing Nominal Voltage Levels

Various nominal voltage levels are evaluated during the auxiliaries system planning phase to identify the best plan. Some of the factors evaluated in this analysis are

- 1) Total bus loads
- 2) Required short-circuit duty
- 3) Steady state voltage regulation
- 4) Motor starting voltage dips
- 5) Economics
- 6) Cable sizing

These factors are interrelated and will be discussed in more detail in subsequent sections.

3.3.2.4 Establishing Alternate Schemes

A number of schemes may be found acceptable in planning for any single auxiliaries power system. Typical schemes are discussed below to illustrate variations.

²American National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036, USA.

³Institute of Electrical and Electronics Engineers, Service Center, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA.

⁴National Electrical Manufacturers Association, 2101 L Street NW, Washington, DC 20037, USA.

3.3.2.4.1 Nomenclature

A simplified single-line diagram of major components for a typical auxiliaries power system is shown in Fig 3.2 as a reference for nomenclature used in the remaining figures. The auxiliaries power system shown in Fig 3.2 receives its power from two sources: the unit source and the station source. The unit auxiliaries buses primary power supply is through a unit auxiliaries transformer (UAT) that connects via a tap to the generator bus between the generator circuit breaker and the unit transformer (UT). The unit must also have a supply of power for startup. This is supplied via the station service (startup) transformer (SST) or the UT, if a generator breaker is used. This startup source also may be used as a stand-by or spare power source and sometimes may be used to supply station auxiliaries during unusual running conditions. The primary of the SST is connected to the high-voltage power system at a point that can be electrically close to or remote from the UT high-voltage connection.

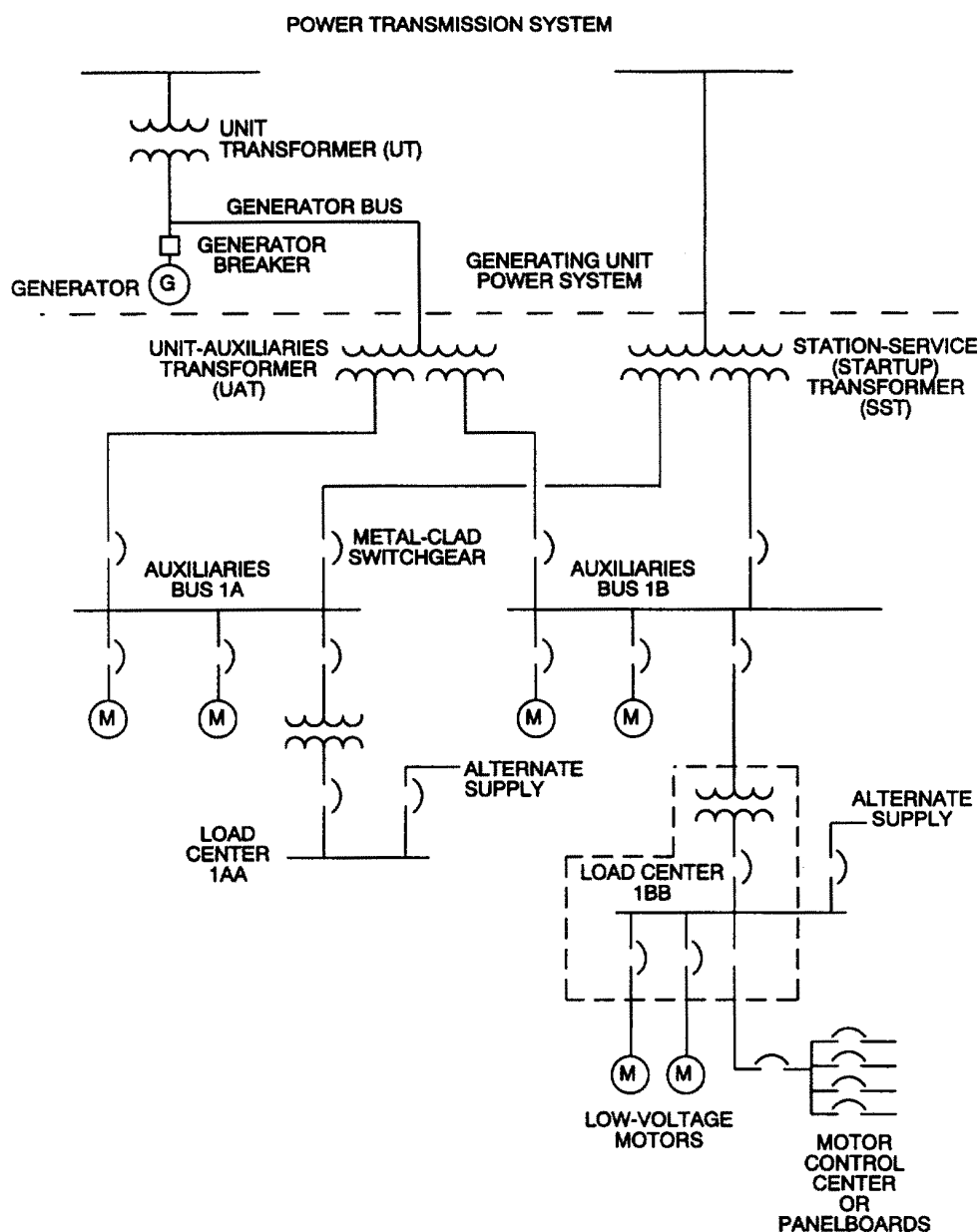


Figure 3.2 — Simplified Single-Line Diagram for Unit Connected Power System

The nominal voltage rating of the auxiliaries buses are usually 2.4, 4.16, 6.9, or 13.8 kV. These voltage levels are referred to as medium voltage. A line-up of metal-clad switchgears forms each auxiliaries (medium-voltage) bus, with individual circuit breakers feeding each of the large motors and/or unit substations or load centers. Sometimes fused contactors or fused load-break switches are used for individual feeders.

Unit substations consist of a step-down transformer, a bus, and circuit breakers as an integral unit. A load center consists of the same components, but it may not be an integral unit and is therefore a more general term. The nominal voltage rating of the unit substations or load centers is usually 480 V or 600 V. Large low-voltage motors and motor control centers are individually connected to the unit substation through circuit breakers. Motor control centers supply small motors and other loads through combination starters and molded-case circuit breakers. The motor control center will have a supply breaker at the unit substation. The main breaker at the motor control center is optional. This optional breaker is usually justified when the motor control center is physically remote from the unit substation, because it may be desirable or required to have a local device to disconnect the source for safety during maintenance.

Other nomenclature will be defined as new equipment is introduced during discussions of other schemes.

3.3.2.4.2 Typical Scheme

After establishing the design criteria, analyzing the load to be served, and establishing acceptable nominal voltage levels, the designer can develop the single-line diagrams. A typical system for a 880 MW coal-fired unit is shown in Figs 3.3 and 3.4. This system is a four bus, unit connected, power supply system. Note that the unit auxiliaries buses are divided into two sets of duplicate buses, with each set of buses being supplied from a different UAT. The duplication of loads, which are segregated to different buses and different unit auxiliaries transformers, may avert an extended unit outage upon loss of any one bus or UAT. Fig 3.4 is an extension of Fig 3.3 and gives the details of the 480 V system, which is also arranged with reliability in mind. Additional reliability may be provided at either the 4.16 kV or the 480 V level by providing alternate supplies to these buses.

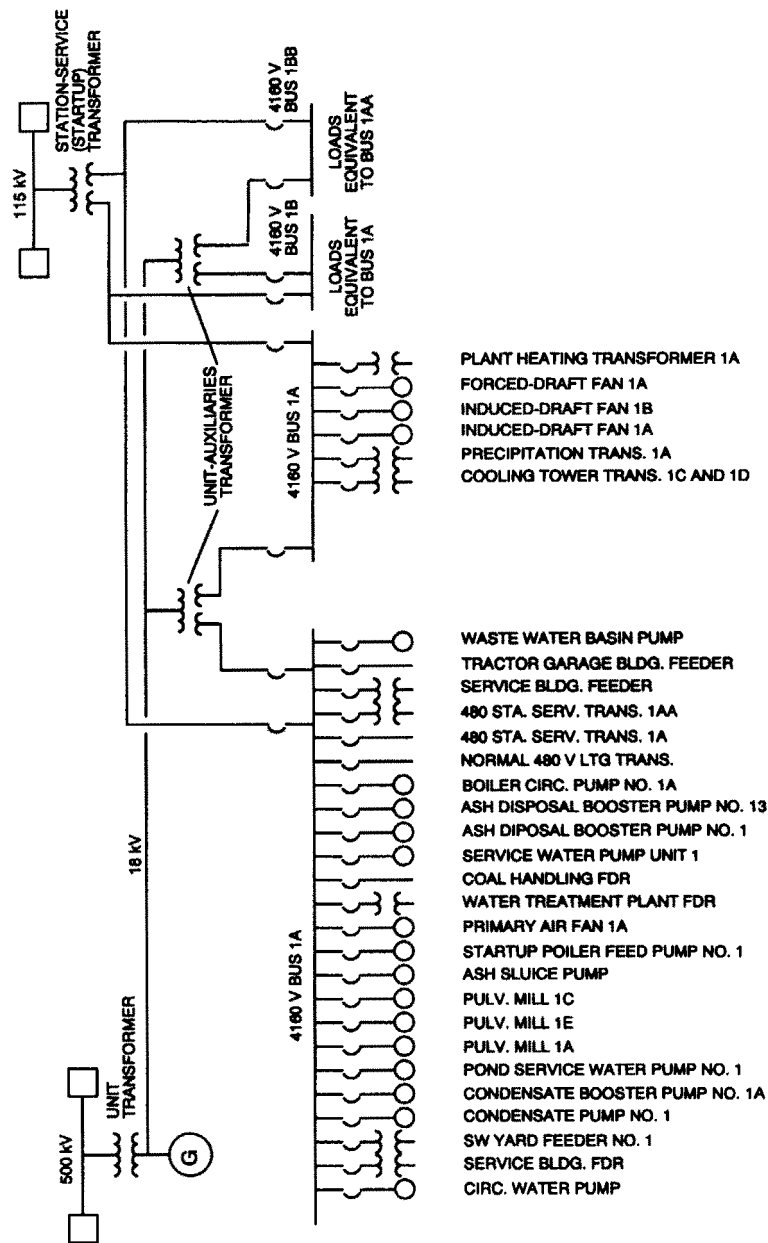


Figure 3.3 – Expanded Single-Line Diagram for 880 MW Coal Fired Unit

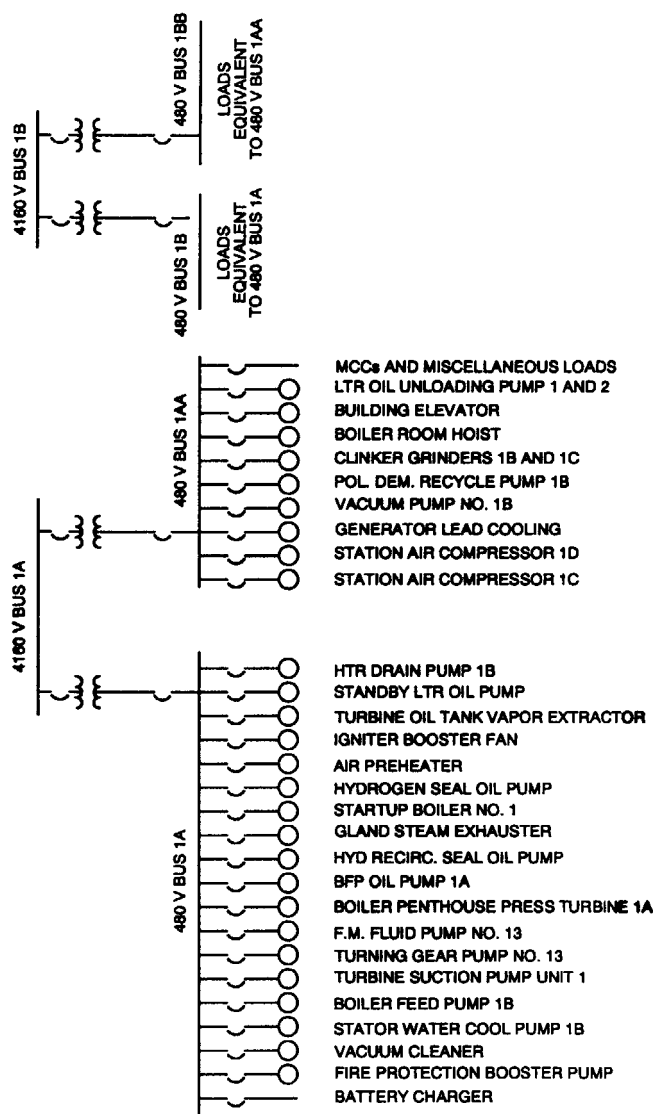


Figure 3.4 — Expanded Single-Line Diagram of the 880 MW Coal Fired Unit

3.3.2.4.3 Station Service (Startup) Transformer Connections

The connection of an SST is an input to the determination of the transmission substation bus arrangement. However, it is rare that this input would change the basic transmission bus arrangement (i.e., straight bus to ring bus). This bus arrangement is determined primarily by the transmission planning engineer to satisfy utility power system stability, reliability, operation, maintenance, and cost. Figs 3.5–3.10 illustrate the most common connections; however, other arrangements and variations do exist.

- 1) *Fig 3.5, Straight Bus.* This is perhaps the simplest of all arrangements. It offers relaying simplicity and cost savings at reduced reliability. Any line fault with breaker failure, or any bus fault, will result in interruption of station and transmission line service.
- 2) *Fig 3.6, Main and Transfer Bus.* For this arrangement, the SST is connected directly to the transmission bus. Any fault on an adjacent bus section or line with a failed circuit breaker results in loss of power to the SST. An alternative connection might have a breaker for the SST to remove a faulted SST from the bus.

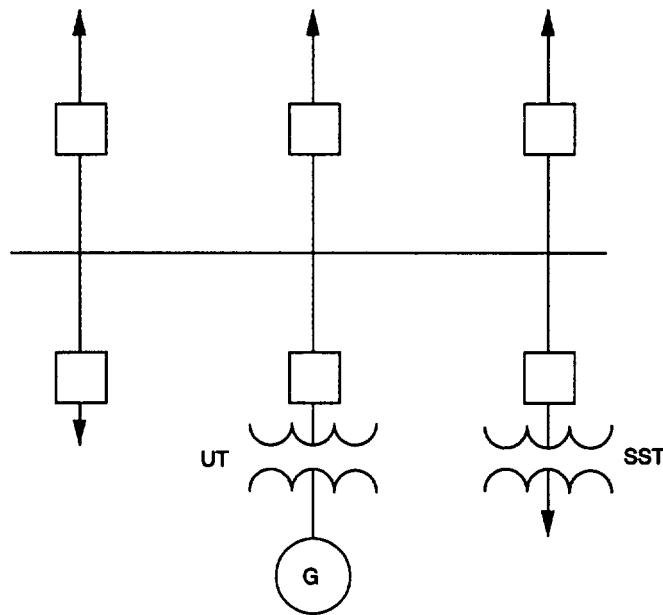


Figure 3.5 —Straight Bus

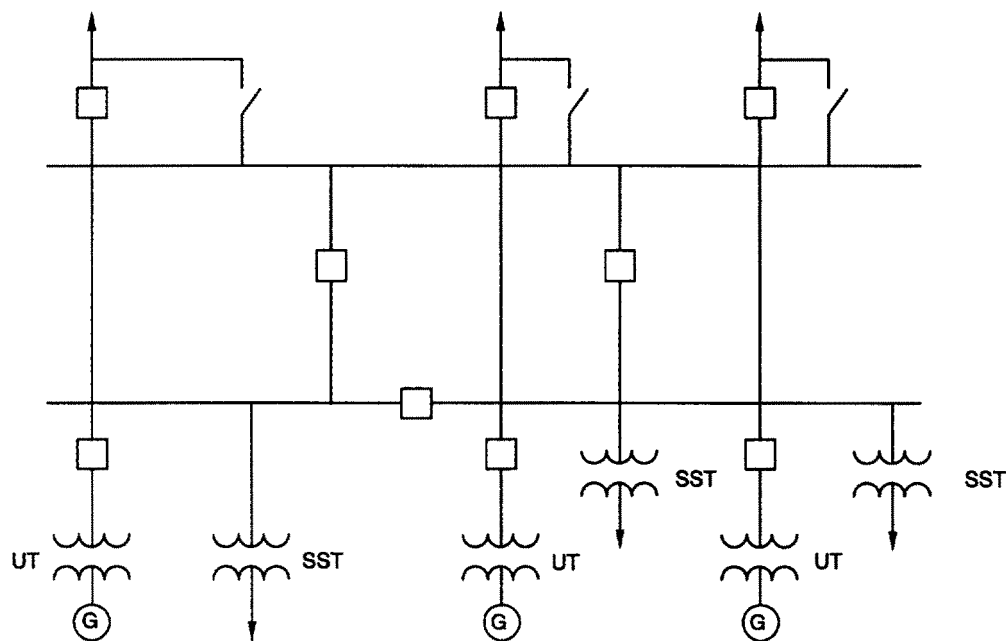
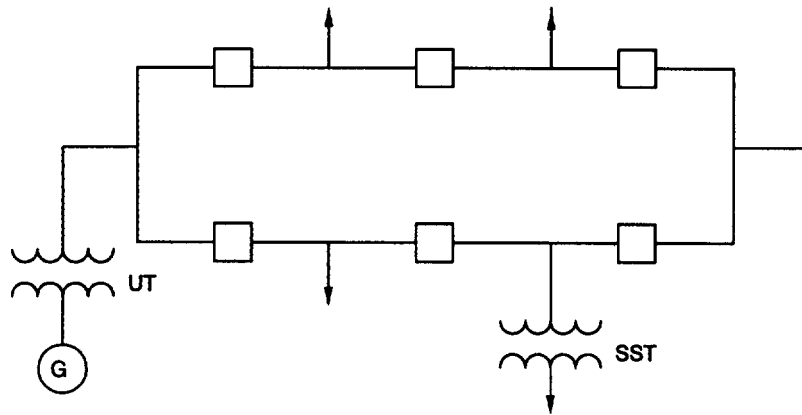


Figure 3.6 —Main and Transfer Bus

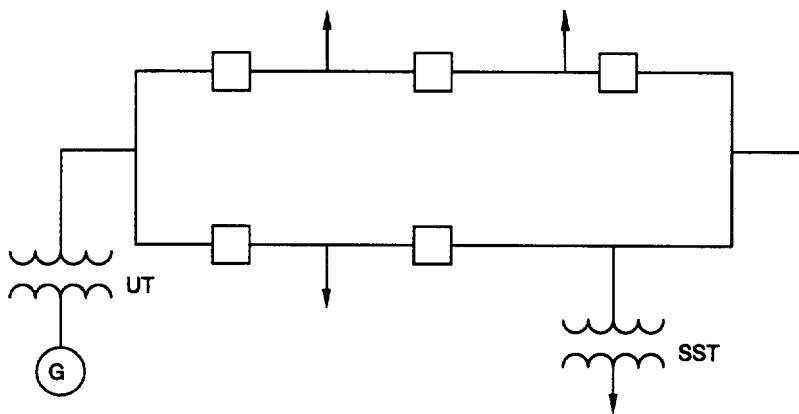
- 3) *Fig 3.7, Ring Bus.* Two ring bus connections are shown. The ring with separate SST bay position is secure against line faults, unless breaker failure occurs. The ring without separate SST bay position is exposed to faults of the line to which it is connected; however, it saves the cost and area required for an additional breaker. Both connections are exposed to the possibility that the bus might split if a fault should occur while a breaker is out for maintenance. This may isolate the SST, and the resulting phase angle across the split system may prevent reclosing.
- 4) *Fig 3.8, Breaker and 1/3 Bus.* This bus arrangement offers more security than the ring bus, since, for certain faults, breaker failure will not cause the SST to be tripped. Two possible connections are shown: one without

a bay position and one with a bay position. The economies of connecting the SST with a transmission line must be evaluated against the exposure to transmission line interruptions.

- 5) *Fig 3.9, Breaker and 1/2 Bus.* This arrangement provides a degree of reliability similar to the breaker and 1/3 bus. Again, *without bay position* and *with bay position* are options to be evaluated.



RING BUS, WITH BAY POSITION



RING BUS, WITHOUT BAY POSITION

Figure 3.7 – Ring Buses

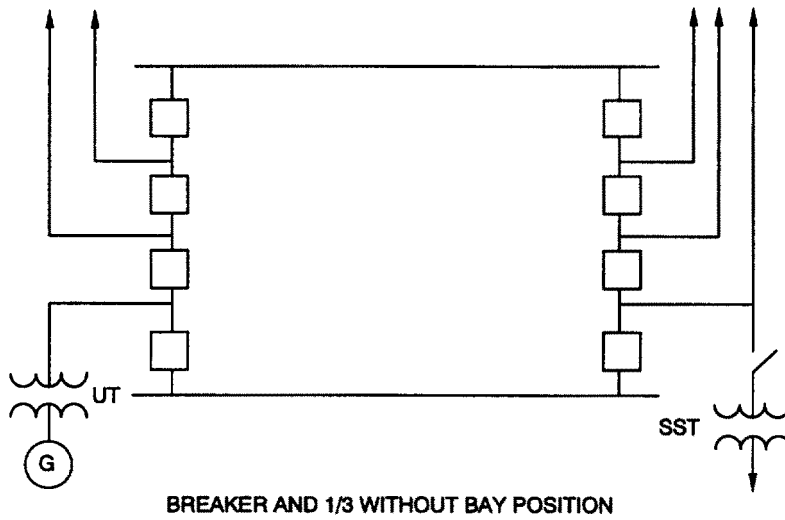
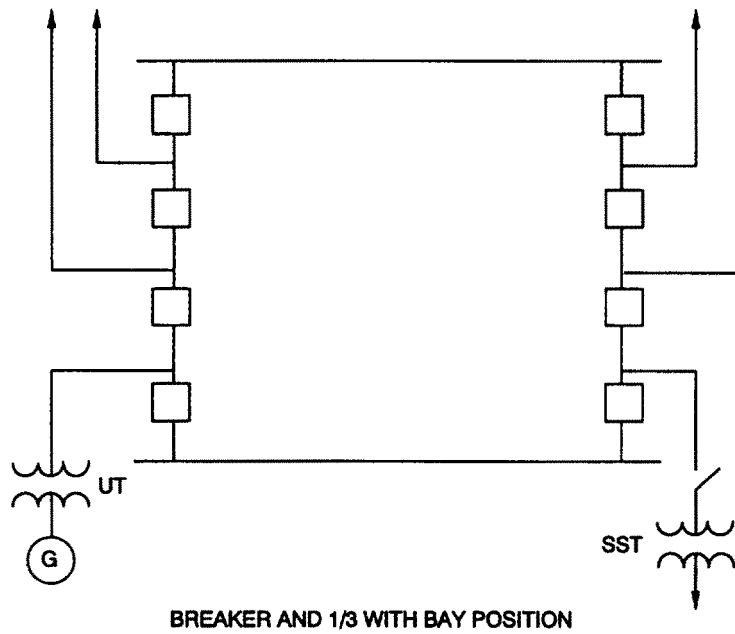


Figure 3.8 – Breaker and 1/3 Buses

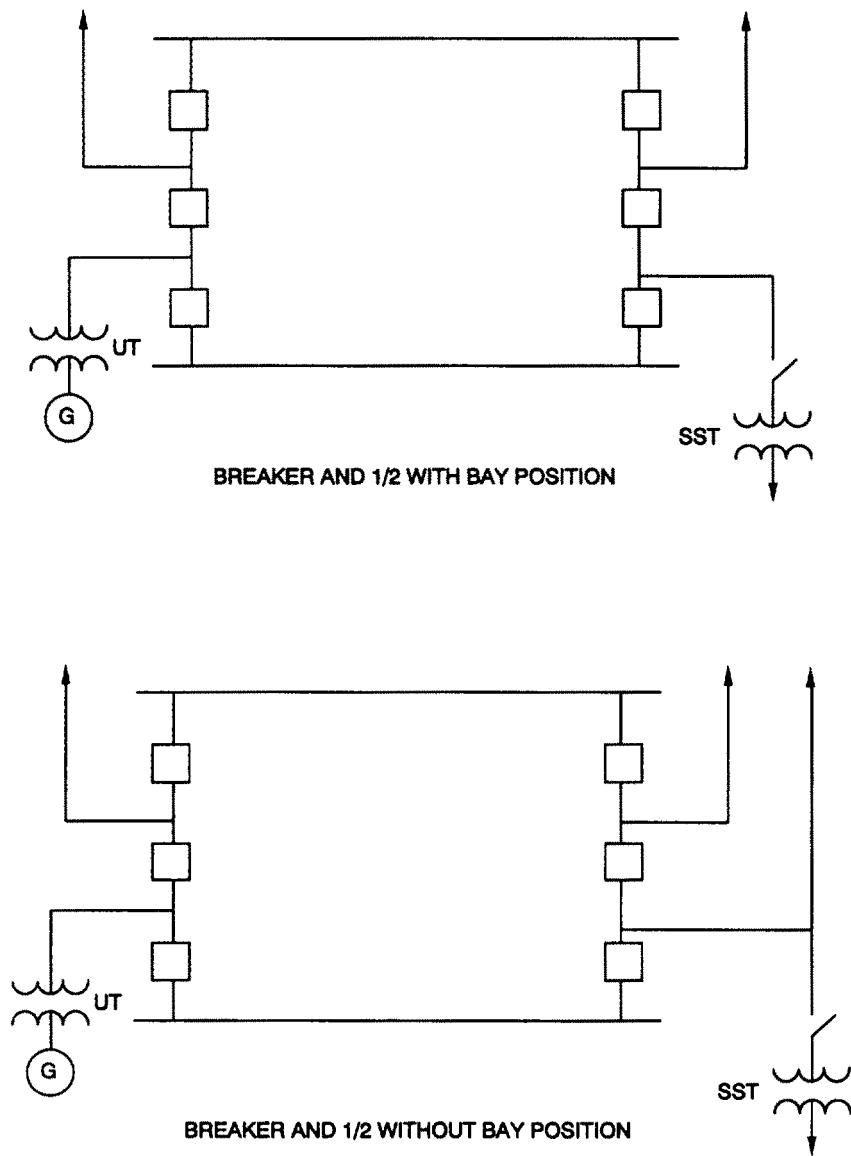


Figure 3.9 – Breaker and 1/2 Buses

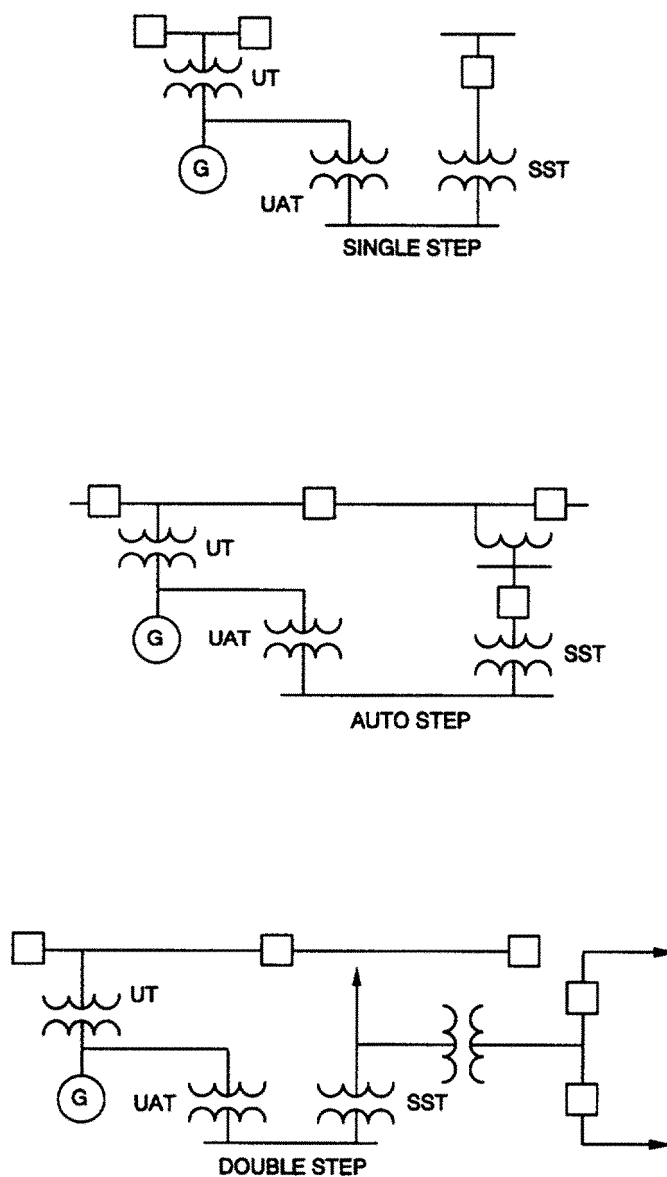


Figure 3.10 – Step Down Techniques

- 6) *Fig 3.10, Step-down Techniques.* Fig 3.10 illustrates step-down techniques that can be used to connect the utility power system to the auxiliaries buses. The single step is a common arrangement where voltage ratios are acceptable.

3.3.2.4.4 Unit Auxiliaries Transformer Connections

Figs 3.11–3.18 illustrate several possible arrangements for the UAT. Since most generating-unit power systems are custom designed, these examples should not be considered all inclusive and are provided to demonstrate basic concepts. Each example arrangement is discussed in more detail below.

- 1) *Fig 3.11, Three Winding Auxiliaries Transformers With Dual Auxiliaries Voltages and Common Auxiliaries Bus.* The windings of the UAT and SST may be of the same or different MVA ratings and impedance. Where multiple UATs are used, the MVA and impedance of each UAT are usually the same. The SST may be sized

for startup load only or to provide an alternate power supply in the event that a UAT is out of service. The common bus that is served from the SST can be used to serve loads that are common to more than one unit in a multiple unit plant. The SST can also be used for another unit, as indicated by the dotted line to Unit 2. This arrangement may afford some economic advantages as well as space savings, though the units lose some flexibility in that only one unit can be started at a time, or only one failed UAT can be spared.

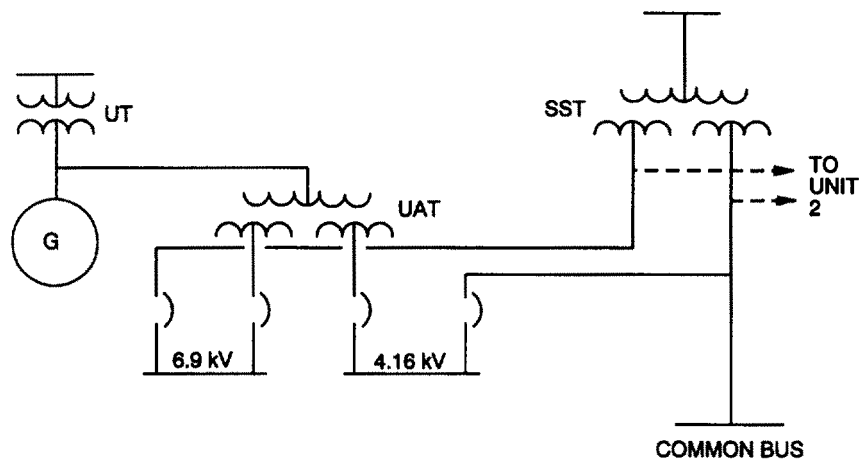


Figure 3.11 — Three Winding Auxiliaries Transformers With Dual Auxiliaries and Common Service Bus

- 2) *Fig 3.12, Three Winding Auxiliaries Transformers With Split Auxiliaries Buses.* This arrangement is similar to that of Fig 3.11, except that each secondary winding is connected to serve two auxiliaries buses rather than one. This scheme has the advantages of lower continuous current per bus and additional isolation for faults. The disadvantage is that the arrangement will require additional room for the bus locations and extra breakers. These additional costs may be offset partially by using lower continuous-current rating for certain equipment.

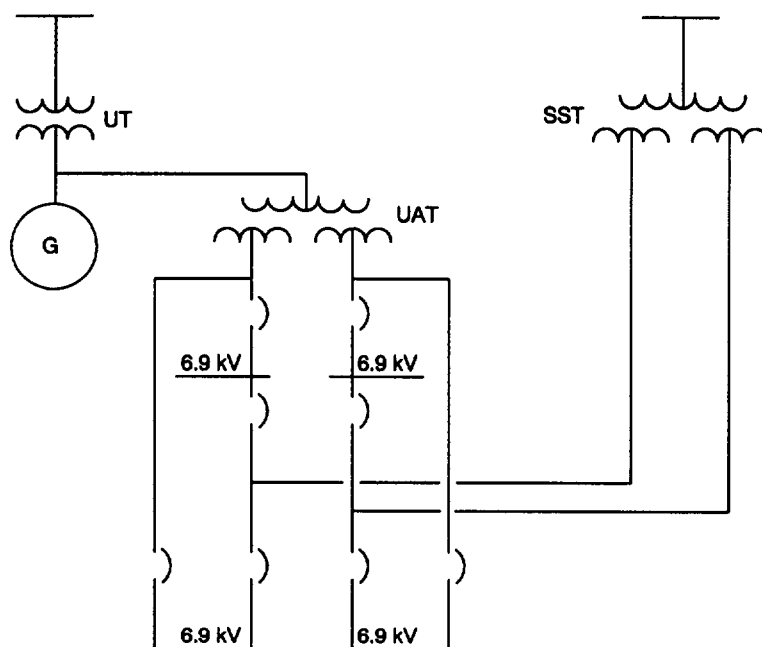


Figure 3.12 — Three Winding Auxiliaries Transformers With Split Auxiliaries Bus

- 3) *Fig 3.13, Two Winding Auxiliaries Transformers With Split Auxiliaries Buses.* The scheme is similar to Fig 3.12 except for the two winding transformers. One of the obvious disadvantages of this scheme is the increased cost to serve the same amount of auxiliary load. However, this scheme may improve the overall power system availability to the one shown in Fig 3.12 due to the two winding transformers.

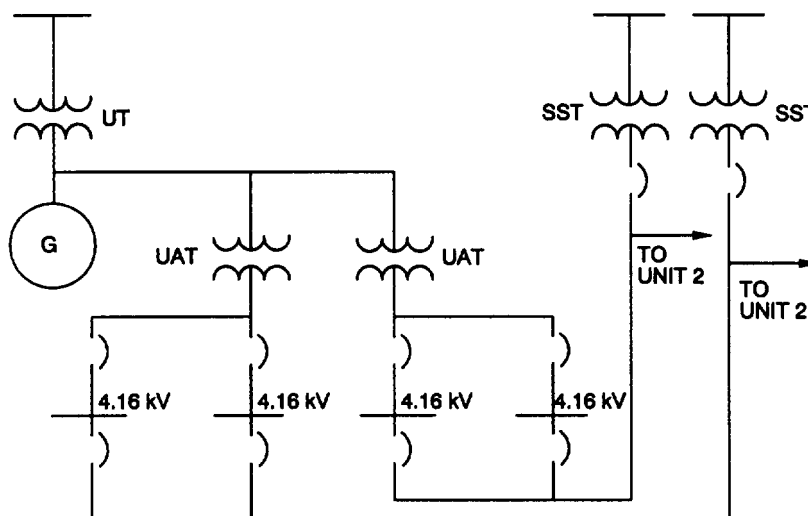


Figure 3.13 – Two Winding Auxiliaries Transformers With Split Auxiliaries Bus

- 4) *Fig 3.14, Dual Three Winding Auxiliaries Transformers With Dual Auxiliaries Voltage.* This arrangement might be used for large auxiliary systems. The MVA ratings, impedance, and voltage are different for each winding of the transformers. Use of different voltages allows segregation of the larger motors to the higher-voltage bus for improved regulation and equipment MVA fault capability while providing a more economical voltage for smaller motors. The three winding transformers save space, which may be critical.

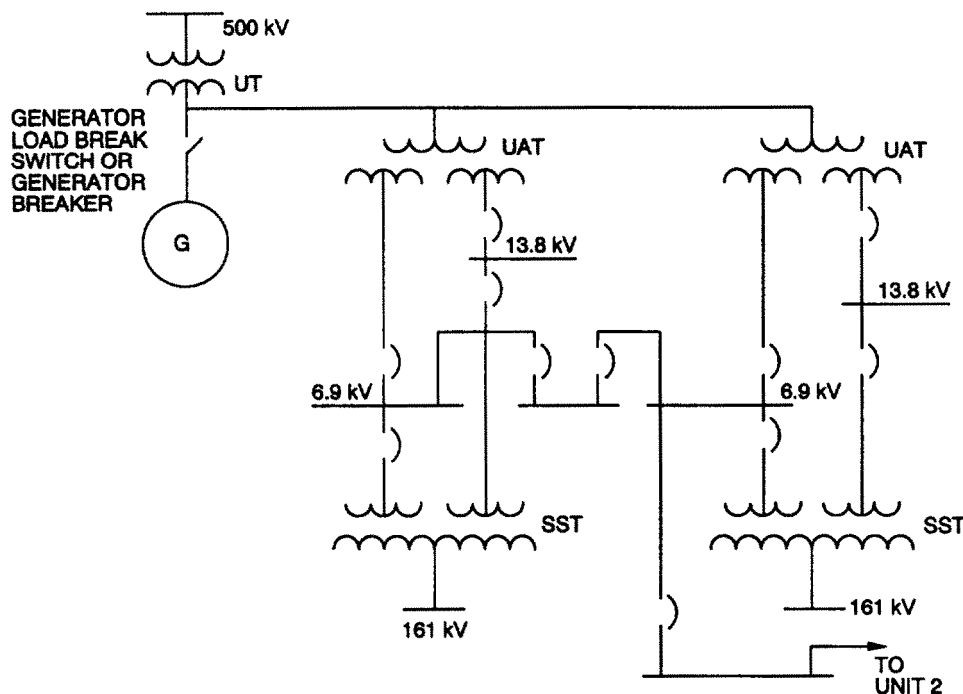


Figure 3.14 – Dual Three Winding Auxiliaries Transformers With Dual Auxiliaries Voltage

- 5) *Fig 3.15, Two Winding Auxiliaries Transformer With Dual Auxiliaries Voltage, Intermediate Auxiliaries Transformer, and Common Auxiliaries Bus.* This scheme is unusual but might be used for a large system serving multiple units. The auxiliaries transformers supply voltage to an auxiliaries (medium voltage) substation. The 13.8 kV buses serve large motors. Smaller motors are supplied from the 4.16 kV buses. Note that alternate sources are provided from other units with appropriate switching. The common buses supply loads common to all units. The disadvantage of this scheme is its complexity. It illustrates how quickly a system can become complex when multiple supplies are provided. The economic advantages and overall system reliability depend on each application.

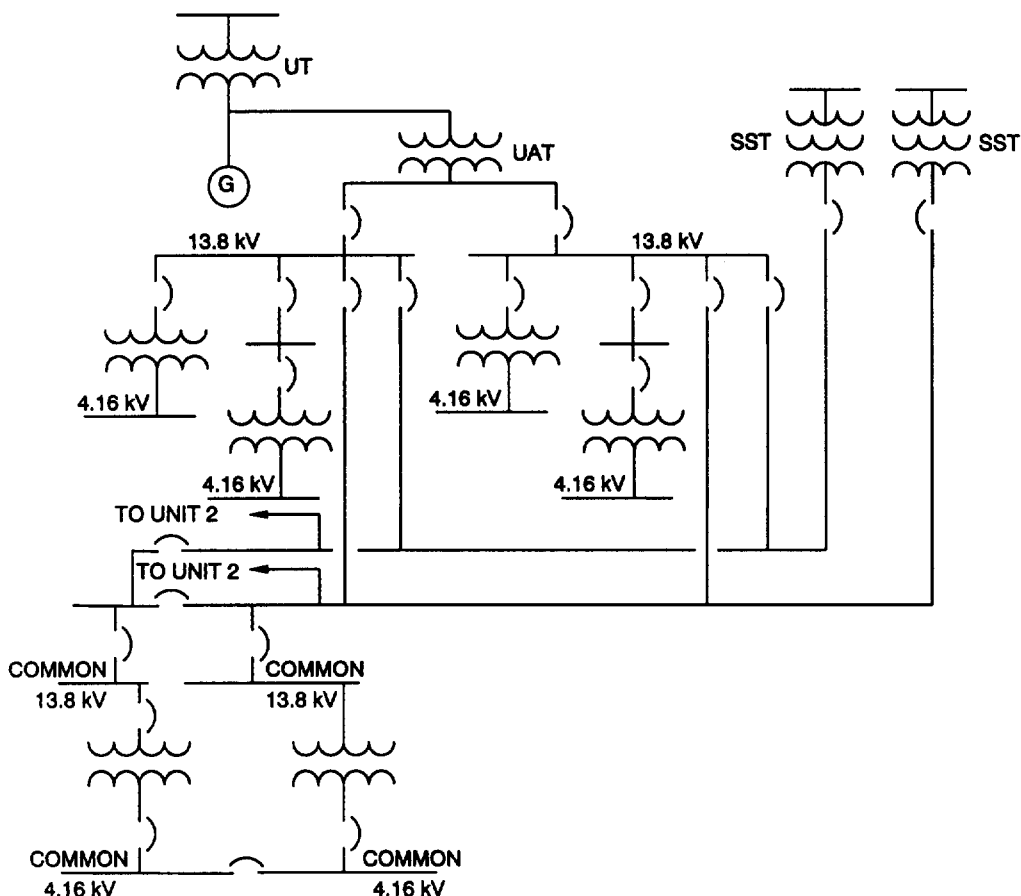


Figure 3.15 – Two Winding Auxiliaries Transformer With Dual Auxiliaries Voltages, Intermediate Auxiliaries Transformers and Common Auxiliaries Bus

- 6) *Fig 3.16, Three Winding UAT – Delta Tertiary SST With Split Auxiliaries Buses and Dual Auxiliaries Voltages.* This scheme is similar to the other three winding auxiliaries transformers split auxiliaries bus arrangements because it has one 13.8 kV winding serving two buses and one 4.16 kV winding serving two buses. The SST arrangement is significant in that the 13.8 kV SST supply is served from the delta tertiary of a system autotransformer. By serving the 13.8 kV direct from the tertiary, one transformation is eliminated and only a step-down to 4.16 kV from 13.8 kV is required. Using the system autotransformer in this fashion exposes it to more faults and exposes the unit power system to system operations considerations. This could degrade the reliability of both power systems.

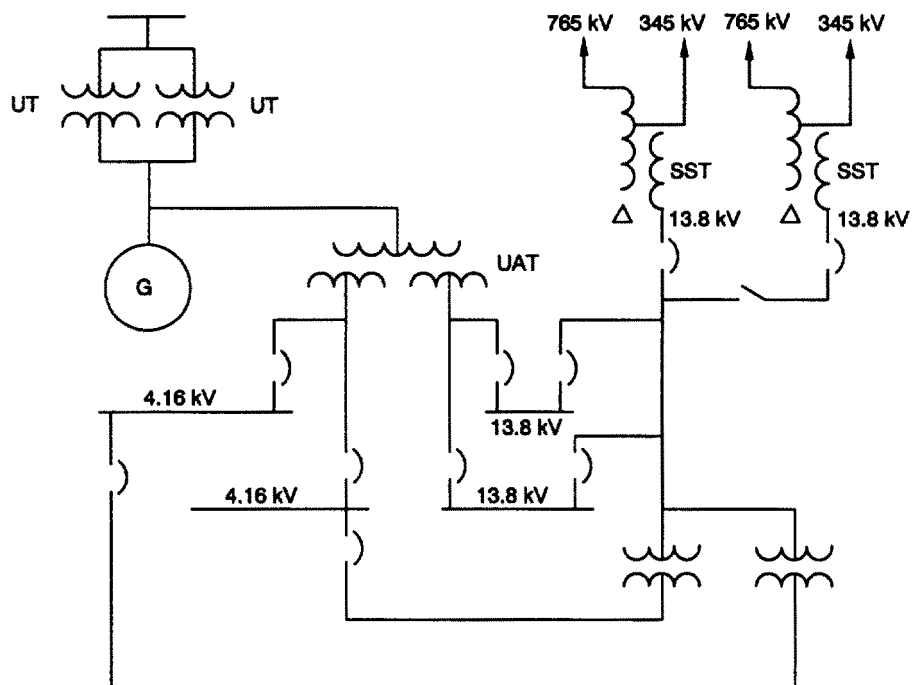


Figure 3.16 — Three Winding UAT — Delta Tertiary SST With Split Auxiliaries Buses and Dual Auxiliaries Voltage

- 7) *Fig 3.17, Three Winding UAT With Generator Load-Break Switch or Generator Breaker.* The significant feature of this arrangement is that a generator load-break switch or generator breaker is used for synchronizing the generator to the transmission system, and for disconnecting it from the transmission system. This allows the SST to be eliminated as the switch or breaker is opened during unit startup with the auxiliaries served through the UT and UAT. By eliminating the SST, there is no need to transfer the auxiliaries from the SST to the UAT after unit synchronization. The load-break switch or generator breaker can be used with any number of combinations of UAT arrangements, as the effect is to eliminate the need for the SST for starting the unit. However, if the SST is eliminated, ties to a neighboring unit are required for an alternate source. This could require larger switchgear or additional UAT.

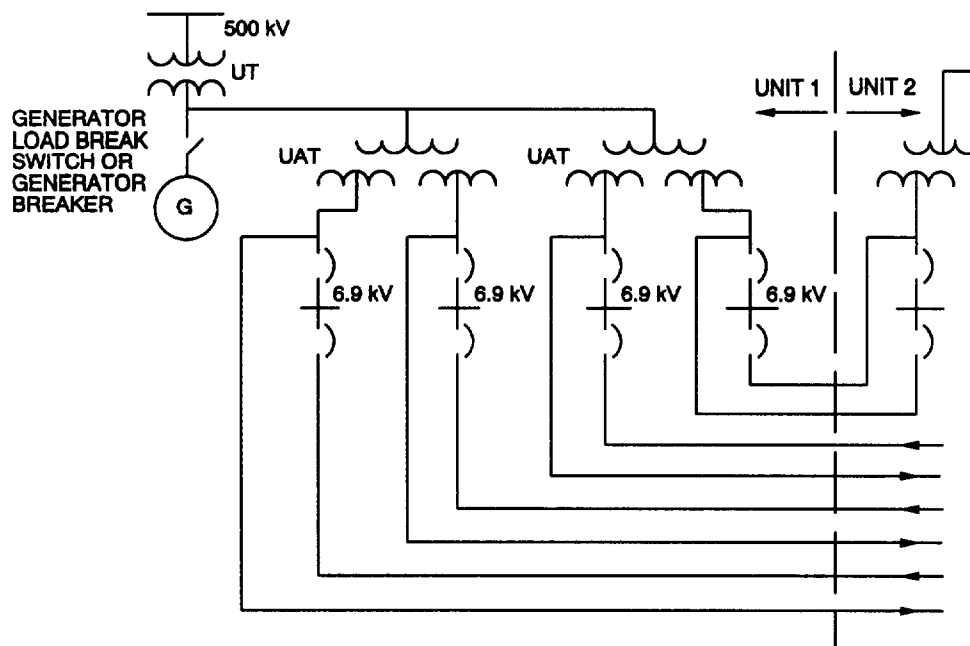


Figure 3.17 — Three Winding UAT With Generator Load-Break Switch or Generator Breaker

- 8) *Fig 3.18, Supply From Station Service Only.* In this scheme, the UAT is eliminated, and the auxiliaries are served completely through the SST. In this example, a number of SST are used, and, similar to the scheme with a generator breaker or load-break switch, there are a number of possible SST arrangements. The significant point is that the UAT is eliminated as well as the need to transfer auxiliaries from a UAT to an SST and vice versa. In considering the economics of this scheme, the cost of additional losses and space for the transformer should be evaluated. Note particularly that the UT must carry total generator output rather than generator output minus the load of the auxiliaries. Thus, the additional load losses through the UT and the additional UT capacity should be evaluated versus SST capital costs and losses. Note also that this example shows multiple UTs that have been applied for increased reliability.

reliability data bases improve, mathematical reliability analysis should become a standard part of the investigation. If a mathematical analysis is not used to evaluate reliability, some subjective evaluation should be used. The critical items in the systems should be identified, and their relative reliabilities should be noted. In this way, perhaps some weight can be placed on the different reliabilities, which should help in selecting a preferred scheme.

3.3.3.3 Flexibility

The auxiliaries system design requires a high degree of flexibility to accommodate design changes that will be made later. Thus, margins on equipment ratings, space for additional equipment, and capacity to account for increased load must be given serious study.

3.3.3.4 Maintenance

While maintenance is largely the responsibility of plant personnel, the auxiliaries systems designer can take certain steps to improve system reliability. For example, the scheme might permit some of the maintenance to be performed with the unit carrying load. This could be accomplished by providing spare capacity for certain loads or alternate feeds to the loads. If the designer specifies the equipment to be purchased for the auxiliaries system, then the expected maintenance of the competitive systems should be evaluated. This information may also influence the on-site spare parts purchasing policy for the plant.

3.3.3.5 Expandability

Most auxiliaries systems experience some expansion or load growth after the initial design. Some causes for increased loads are as follows:

- 1) Larger mechanical loads than anticipated
- 2) Coal and ash handling facility modifications
- 3) Efficiency and availability improvements (i.e., balanced draft conversions)
- 4) Unit cycling requirements — electric drives for existing turbine-driven load (i.e., boiler feed pump)
- 5) Environmental — precipitators and flue gas desulfurization

In any case, expansion is almost inevitable, and the designer is well advised to make allowance for future changes. The exact amount of margin to be provided is a matter of engineering judgement for the designer, as it may vary among companies. For example, some companies provide for a future load growth of $X\%$, where the determination of an amount (X) of future load growth capability depends on several factors including costs and the probability of the modification.

3.3.3.6 Performing Detail Design Calculations

Design calculations allow a complete technical evaluation of the plans under study to determine the merits of each compared to the design criteria. These calculations should include short-circuit and continuous current, steady state voltage profiles and transient voltage dips during motor starting, etc. Once the final plan is chosen, these detail calculations provide equipment characteristics such as transformer MVA rating and impedance, breaker ratings, etc. This is an integral input into the equipment specifications.

3.3.3.7 Detail Cost Analysis

There are several components of costs that should be evaluated, as well as several methods of economic evaluation that are appropriate. The details of these evaluation techniques are beyond the scope of this document. There are, however, many excellent texts on the subject.

The costs to be evaluated include capital, maintenance, and operating costs. Note that maintenance costs and operating costs are distinct, since the maintenance costs refer to the costs associated with items such as annual maintenance, repairs, and replacement parts for the system equipment. The operating costs refer to the costs associated with items

such as losses or replacement power. These separate cost components may individually influence the overall economic evaluation of the plans.

3.3.3.8 Choosing a Scheme

After evaluating all plans for reliability, flexibility, maintenance, expandability, and cost, a final scheme is chosen.

3.3.4 Preparing Equipment Specifications

The equipment specifications can be written based on the detailed design calculations of the chosen scheme. The specifications should assure that all requirements determined in the detail design calculations, and any special requirements, such as operating duty cycles, are met by the manufacturer. The form of such specifications is beyond the scope of this text, although many IEEE documents provide guidance in preparing the specifications.

3.3.5 Evaluating the Bids

The details of the bid evaluation process are also beyond the scope of this text, but it is the next step in the design process. The methods of evaluation may vary widely, but the results should reflect evaluation techniques similar to those used in 3.3.3.

3.3.6 Reviewing and Finalizing Design

Once the equipment for the auxiliaries system has been specified and purchased, the manufacturers can supply the designer with design documents for the equipment. At this point, the design should be reviewed, using the design data for the equipment, to determine if there are any equipment changes that may impact the auxiliaries system design. For example, a large motor may have an inrush current that exceeds specifications. This may result in unacceptable voltage drop during starting. Major changes are generally infrequent, but the designer should check the design data for possible changes.

3.4 Transmission System and Generating Unit Considerations

The power system discussed in this section encompasses the power transmission system and the generating unit.

3.4.1 Transmission System

3.4.1.1 Voltage Variations

The maximum and minimum expected voltages to the primaries of the station service transformers are necessary data in determining the voltage regulation requirements of these transformers. These expected voltages are obtained from the transmission planning engineer who analyzes the transmission system by running a series of load flows. For a more accurate representation, these load flows should be run with the station service load. If the station service load is neglected, then regulation must be calculated through the transmission system (see 3.4.1.2). The minimum system voltage, maximum system impedance, and maximum station service load determine the minimum voltage. The maximum system voltage, minimum system impedance, and minimum station service load determine the maximum voltage.

This analysis is important in determining the station service transformer impedances and tap requirements. Large voltage variations may necessitate the use of load tap changers or transformer thermal load limits that are lower than their top ratings. Also, transformer overexcitation limits should be considered, especially when applying taps below nominal voltage.

3.4.1.2 Representation of Transmission System as Short-Circuit Impedance

For station service voltage regulation purposes, it is usually adequate to represent the power system as a voltage source behind a short-circuit impedance. The maximum and minimum power system short-circuit impedances can be obtained by investigating combinations of line and unit outages. This is usually done with a digital short-circuit program. For maximum short-circuit contribution from the transmission system, the maximum transmission system voltage and minimum transmission system impedance are used. The SST is the only component that can be changed to limit the fault contribution from the transmission system. Therefore, for a given station service load, transformer tap setting, system voltage, system short-circuit impedance, and auxiliaries bus short-circuit rating, the required transformer impedance(s) can be determined. Of course, this impedance must satisfy voltage regulation requirements as noted in 3.4.1.1.

3.4.1.3 Phase Sequence and Phase Angle Difference

For three-phase power systems, phase sequence identifies the order in which the three voltages reach their positive maximum values relative to a fixed reference point. When interconnecting individual equipment and/or power systems, the phase sequence of the two must be equivalent. Proper care is required when dealing with phase sequence sensitive equipment such as motors, generators (proper rotation), transformers (proper phase shift), certain types of protective relays, etc. Thus, when designing a new or modifying an existing power system for a generating station, the phase sequence of the system and equipment must be considered in conjunction with the phase angle difference described below.

A difference in phase angle between the unit and the station power supplies can result in severe duty on equipment such as transformers, motors, and breakers during the transfer from the SST to the UAT and vice versa. Phase angle differences are both steady state and transient in nature. Transient phase angle differences in the auxiliaries power supply can be caused by disturbances on the utility power system or, more frequently, by an automatic transfer from the unit transformer to the startup transformer. Section 4. discusses auxiliaries bus transfer. The steady state phase angle difference between the UAT and the SST is caused by either (1) the transmitting of power through the power system or (2) three phase transformer winding connections.

- 1) The generating unit and SST(s) may be connected to the transmission system at two different electrical points although they are at the same physical location. An example of this might be a UT connected to 500 kV and the SST connected to 115 kV. These two transformers may be connected at the generating unit by an auto or step-down transformer, or they may only be connected by virtue of the interconnected transmission system. The maximum angle difference between the generating unit and the SST(s) for the worst power flow is determined by the transmission planning engineer by running load flow cases. The power system should be designed and the equipment purchased to be capable of tolerating the maximum angle determined, since this angle cannot be judiciously adjusted to zero.
- 2) The phase angle difference due to transformer winding connections (i.e., wye-delta, delta-zig zag, etc.) must also be examined. In cases where two systems are to be paralleled, such as during parallel transfer (see Section 4.), the phase angle difference between the two sources must be zero. Even in the case of radial systems, it is good practice to maintain a zero phase difference at each voltage level, where practical, in the event these systems are inadvertently interconnected or some form of automatic throw-over scheme is added. Note that this may require the use of transformers with nonstandard phase connections. An example of correct and incorrect connections is given in Fig 3.19.

3.4.2 Generator

- 1) *MVA Rating.* The MVA rating of the generating unit has a direct influence on the design of auxiliaries systems. In general, the larger the main generator, the larger the power consumed by the auxiliaries system. In the past, coal-fired unit auxiliaries power systems consumed 5% to 8% of generator output. However, with the rapid increase in stringent environmental laws, the power consumed by auxiliaries power systems has risen in some coal-fired units to 10% to 12% of the generator rating. The increase in the auxiliaries system capacity has also resulted in the design of the auxiliaries system becoming more complex. As the MVA rating of the unit increases, the desired reliability of the unit increases correspondingly. This is because (1) the larger units are intended for base load operations, and (2) the initial cost of the unit and energy replacement costs are very high.

- 2) *Voltage Rating.* As stated in ANSI C50.13-1977 [B1], “generators shall operate successfully at rated kilovoltamperes (kVA), frequency, and power factor at any voltage not more than five percent above or below rated voltage, but not necessarily in accordance with the standards of performance established for operation at rated voltage.” This implies that the auxiliary power supply system connected to the main generator bus should allow a $\pm 5\%$ generator bus voltage swing.

If this is true, it may necessitate increasing the number of auxiliaries buses or the use of transformers with load tap changers. An alternative to this is to determine the required generator bus voltage swing. This requires a study of UT regulation, tap settings, power system reactive power requirements, transmission system voltage schedules, and the coordination of these with the unit auxiliaries, station service, and load center transformer tap settings.

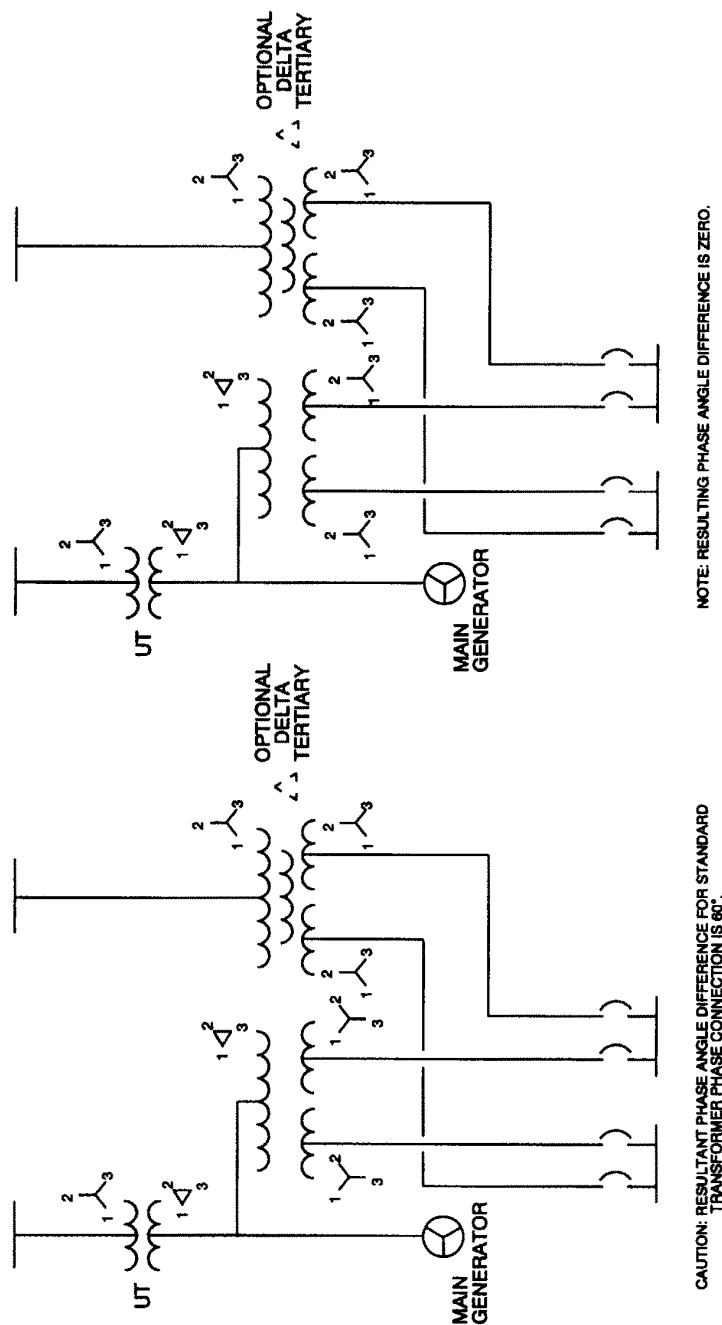


Figure 3.19 — Phase Shift Due to Three Phase Transformer Winding Connections

3.4.3 Unit Connections

A primary decision to be made for the unit connection is whether or not to use a generator breaker or load-break switch (see Fig 3.14). This decision may not rest solely on the auxiliaries power supply system requirements. However, it does have a major impact on the auxiliaries power system design. The most significant impact of applying a generator breaker or a generator load-break switch is the possible elimination of the station service transformer. In the event that the station-service transformer is retained, it could serve as a third source of power to the auxiliaries system. In the absence of the station service transformer, the auxiliaries system under unit startup or similar conditions is fed through the unit transformer, and the alternate source is from neighboring units. Consequently, the power from the transmission system to the auxiliaries system flows through two transformers: the UT and the UAT. Thus, voltage regulation and the short-circuit contribution from the system will be dependent on the relative strengths of the transmission system and the tap setting of the UT. The tap of the UT is normally set for the operation of the transmission system and not to supply the auxiliaries.

3.4.4 Station Service Transformer Connections

The station service transformer connection requirements are influenced by the following factors.

3.4.4.1 Transmission System Nominal Voltage

The transmission system supply voltage is usually greater than or equal to 115 kV. The transformations necessary are dependent on this nominal voltage and the availability of transformers to step this voltage down to the auxiliaries power system voltages. For example, for a transmission system of 500 kV, it may be more economical to step-down the voltage to an intermediate level, such as 115 kV or 230 kV, and then step-down the voltages to 6.9, 4.16, or 2.4 kV. Another option is to use the tertiary of an existing autotransformer as the source of the desired voltage (see Fig 3.16).

3.4.4.2 Transformer Type

The extent to which the type of transformer (i.e., two or three winding) affects the design is dependent upon the design and operating philosophies of individual utility companies. For example, some utilities prefer to have balanced winding loadings on three winding transformers. Under such conditions, the secondary voltage is limited to one choice. Dual auxiliaries voltage systems would require two winding transformers for this restriction. Other utilities have successfully utilized three winding transformers with secondaries at unequal loads and voltages.

Another design factor is the manufacturers' impedance tolerance. The standard tolerance is 10% and 7.5% for three and two winding transformers respectively (see ANSI C57.12.00-1987 [B3]). The difference in tolerance can have a significant effect on the preliminary design phase of the auxiliaries power systems.

In the preliminary design, the exact impedance of the auxiliaries transformer is initially unknown. In order to calculate the transformer impedance, the manufacturer's impedance tolerance is appropriately taken into account for short-circuit and voltage regulation calculations. A difference of 2.5% in impedance tolerance may be critical under certain design conditions and may warrant a change. For example, the change may materialize in the preference of one type of transformer to another, the reduction in auxiliaries bus load, or the change in design boundary constraints.

3.4.5 Transformer Duty

The UAT and SST are subject to experiencing special duties. Depending on the design of the power system, these transformers may be exposed to synchronizing surges, large inrush currents due to transfer of the auxiliaries and starting of larger motors, etc. Since a UAT is connected to the generator bus, it can be exposed to severe through-fault conditions that cannot be isolated from the generator if a generator breaker is not used or fails to operate. It should therefore be designed to handle the fault decrement of the generator resulting from the trapped flux in the machine. In addition, the UAT has the exposure to overvolts per hertz events caused by improper generator voltage and/or speed or sudden loss of load (full load rejection).

These special duties should be quantified and made part of the transformer specification. They are addressed in more detail in Section 9.

3.5 Bibliography

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4. Startup and Shutdown Requirements

4.1 Introduction

Auxiliaries for a power station generating unit and its prime mover (turbine or engine) require electric power service during startup and shutdown periods. This service is normally supplied from off-site sources through the transmission system and, in the case of a large or multi-unit plant, through its own switchyard. This supply, with its related equipment, is identified as either the station service system or the startup/shutdown source. After a unit generator has been synchronized to the system and partially loaded and transfer has taken place, service to its auxiliaries is supplied normally from the unit generator terminals through a unit auxiliaries transformer. This supply is identified as either the unit auxiliaries system or the normal source.

Station service systems should be suitable for supplying continuous load, short-time overload, and transient overload requirements of the unit auxiliaries. They also should provide margin for future load growth. Quality of power is an important consideration that must meet criteria for frequency, phasing, and voltage control.

Power from the station service system is essential during unit startup and shutdown periods in which the unit generator cannot supply its auxiliaries. The station service system must provide lubrication and sealing oil during and after coastdown, remove residual heat, purge the boiler, maintain condenser vacuum, and provide service to other critical components and protective systems.

Onsite power sources, either storage batteries or engine-driven generators, are used to provide standby or alternate electric service to critical equipment in the event that both the normal and startup/shutdown sources fail during operation. When this occurs, and the power system has been completely shut down or blacked-out, the design bases of the plant may require that the unit be restarted (called a *black start*) from a power source that can be manually initiated. Generators driven by hydraulic turbines, gas turbines, or diesel engines are used for this and other emergency shutdown tasks until the startup source is restored. Due consideration should be given to size and cost. If these sources require stored electrical energy for startup, such as field flashing, controls for diesel generators, or ignition, it is usually obtained from storage batteries.

4.2 Power Requirements

Power requirements for unit auxiliaries at startup (or shutdown) are dependent on the size and type of unit and the degree of reliability. The design should include considerations for continuous load, short-time and transient overload, and a margin for future growth.

4.2.1 Continuous Capability

The continuous capability should supply maximum power requirements of all electrical auxiliaries in any combination in which they may be used during plant operation from the station service system. Where more than one unit is supplied from a common station service system, consideration should be given to the possibility that a unit in normal operation may trip from full load and transfer its shutdown auxiliaries to the common station service system during the startup of another unit's auxiliaries. Instead of designing a system to supply auxiliaries requirements for two units, it may be acceptable to impose engineering or administrative load limitations. The system should also be able to react in the event that station load is suddenly lost.

4.2.2 Short-Time Overload Capability

Certain auxiliaries served by station service systems may be required, for limited periods, to carry loads greater than those existing at plant full load. Examples are circulating water pumps filling the system before full syphon conditions are established, induced-draft fans handling cold air, motor-driven startup boiler feed pumps that will be replaced by turbine-driven pumps at a more advanced stage of startup, and electric boilers not used during full-load operation. Affected equipment or components of the service system should be capable of carrying these overloads for appropriate periods without producing voltage profiles or temperature rises outside prudent limits. While reviewing equipment load requirements that are greater during starting than at full-load operating conditions, equipment whose load requirements are lower during starting should also be noted. A typical example would be the forced-draft fans of a unit, which operate substantially below nameplate rating during startup. Incorporating both types of load in a common portion of the system may reduce the overall supply requirements.

4.2.3 Transient Overload Capability

Station service systems should have the capability of supplying electrical auxiliaries during the starting or restarting of the largest load. When the largest load is a motor driving high-inertia loads, such as an induced-draft fan, the starting transient duration may be up to 60 s. Voltage profiles during such transients are not required to satisfy criteria established for continuous operation or short-time overload, but they must be adequate to assure that no running motor

will stall and no motor-starter contactor will drop out. Acceptable equipment operating voltage ranges should be confirmed with the manufacturer. If load tap-changing (LTC) transformers are used in the power system, it should be assumed that these tap changers do not operate fast enough to apply significant correction during such transients.

The system should be capable of supplying unit auxiliaries required during an automatic transfer of the buses from the normal to the startup/shutdown source. Voltage profiles immediately following such transfers should meet the same criteria as those established for the motor-starting transient. Within approximately 60 s, the profiles should meet criteria established for continuous operation. If transformers with LTC are used, it should be assumed that significant correction is not applied until after the 60 s period.

4.2.4 Margin for Load Growth

Station service system design should allow for auxiliaries that may be added after the plant is placed in service. An acceptable margin for future loads should be included in transformer and feeder cable capacity and space should be provided for switchgear and motor control center additions. Short-circuit withstand capability of switch-gear buses should be sufficient to avoid transformer voltage regulation problems and allow for future growth. This last margin generally will be created by increasing transformer impedance at the expense of voltage regulation. For that reason, it is often impractical to make large allowances for future load growth.

4.3 Quality of Power

Quality of power is a term used herein to designate system characteristics such as availability, frequency, phasing, wave form, and voltage control. The design should consider the effect these characteristics have on satisfactory operation of the system and its components.

4.3.1 Source Availability

Availability of station service may affect the availability of a generating unit. Replacement power costs, incurred when an otherwise serviceable generating unit cannot be started, may be a significant item. In addition, a shutdown of the unit without power to run the auxiliaries may cause equipment damage, the repair of which will delay restart and incur replacement power costs. For these reasons, the cost of an alternative power source is usually justified, particularly in a multi-unit station. This alternative power source may be the station service system, an onsite source, or both. The basis of selection should include a review of the reliability of the transmission grid, outage costs, and onsite source equipment costs.

4.3.2 Frequency

When a transmission system is supplying power through the station service system, the frequency at normal operation is maintained at approximately $60 \text{ Hz} \pm 1\%$. Exact tolerances are dependent on utility system operating conditions and procedures. Continuous operation outside of these tolerances may significantly affect output of larger unit auxiliaries (reduced pressures and flows) and may cause vibration problems in the turbine blading. When the power supply is from an onsite ac source, frequency is usually maintained at 60 Hz with a tolerance within $\pm 3\%$. Exact tolerances are dependent on the specific generator and the type of governor control used; however, operation of equipment beyond its V/Hz rating can cause equipment damage.

4.3.3 Phasing

When an alternative source is available continuously to accept a transfer of the auxiliaries bus from the normal source, its frequency and phasing should match that of the normal source. Excessive phase angle differences may result in significant transfer of power from one source to the other during parallel operation. Phase angle differences relating to auxiliaries bus transfers, parallel source operation, and related equipment damage are described in more detail in 4.6.

4.3.4 Phase Balance

Phase-to-phase voltages should be balanced within 5%. Percent unbalance is defined (see NEMA MG 1-1987, 14.34B [B6]⁵) as 100 times the maximum voltage deviation from the average voltage divided by the average voltage. The reason for this requirement is that, at normal operating speed, the motor phase current unbalance will be 6 to 10 times the voltage unbalance. This phase current unbalance produces winding currents significantly in excess of those present under balanced voltage conditions. The increased currents will cause a higher-than-normal temperature rise in the motor and may require the derating of the motor nameplate horsepower to prevent long-term damage. Under a condition of 5% voltage unbalance, the motor derating factor may be as large as 75% of the nameplate horsepower. An additional effect of voltage unbalance is that the locked rotor and breakdown torques will be decreased, and the motor may no longer be adequate for its intended application. The above applies specifically to induction motors. Situations in which larger unbalanced voltages exist, or in which synchronous motors are supplied by unbalanced voltages, should be stated in the motor specifications.

4.3.5 Waveform

The voltage waveform should be sinusoidal with a deviation factor not exceeding 0.10 (NEMA MG1-1987, 22.42 [B6]). Deviation factor is defined as the ratio of the maximum difference between corresponding ordinates of the wave and of the equivalent sine wave when the waves are superimposed in such a way as to make this maximum difference as small as possible.

4.3.6 Voltage Control

Startup/shutdown source voltages should furnish a range of voltage that ensures acceptable operation of the auxiliaries. The normal source is usually a transmission or distribution system voltage that will be transformed onsite to a lower utilization voltage. ANSI C84.1-1989 [B2] establishes voltage ratings and recommends that source voltages should have a sustained value of between 98% and 105% of the nominal voltage, corresponding to Range A. It should be noted that these values are recommendations only, and the required range is a function of the specific design of the auxiliaries service system and the specific operating ranges of the equipment. Most auxiliary equipment will operate within a $\pm 10\%$ tolerance of their nominal voltage rating. The compromise made between increasing transformer impedance to lower short-circuit availabilities and decreasing transformer impedance to raise operating voltages will also affect the required source voltage range. Proper selection of transformer impedances and tap settings, in conjunction with a station design that minimizes voltage drops, should result in selection of a range within the normal operation of the source voltage. When a range of voltage is required that is wider than the capability of the source, it may be necessary to reconsider the single-line design before employing load tap changers in the transformer stepping the voltage down to utilization level. Both system and auxiliary equipment utilization voltages are addressed in greater detail in Section 5.

Source voltages may have transient values outside the above range. Transient overvoltages caused by lightning or switching must be limited by appropriate surge protection to prevent damage to transformers, switchgear, and utilization equipment on the system. Transient under-voltages produced by faults on the transmission or station service system are of short duration (because of rapid fault clearing) and have little effect on utilization equipment.

Transient undervoltages caused by starting large motors are frequently of sufficient duration to warrant careful study. The magnitude of such transients depends on the ratio of the source impedance to the motor locked-rotor impedance. The source and feeder voltage regulation will be adversely affected by other running loads and by transformer and cable impedances between source and motor.

Transient undervoltages caused by sudden transfers of large blocks of load from the normal to the startup source may be unacceptable if the voltage difference between the new source and the residual bus exceeds 1.33 pu. This may occur if the dead-bus time of the transfer exceeds 4–6 c. Dead-bus time is the time in which the auxiliaries service bus is

⁵The numbers in brackets, when preceded by the letter “B,” correspond to the Bibliography in Section 4.10.

completely without power. Slower transfers may require load shedding to maintain the voltage within acceptable limits. Voltage transient conditions caused by bus transfers are described in more detail in 4.6.

In general, the startup source should have a short-circuit capability greater than 30 times the magnitude of its steady-state load. In this case, the startup source is assumed to be the high side of the station service transformers. Therefore, a total demand of 50 MVA would require that the source have a minimum short-circuit capability of 1500 MVA. If this requirement can be met, the transient undervoltages may be acceptable, and a narrow range of sustained source voltages may permit acceptance of a lower short-circuit capability. However, it should be emphasized that the above statement is a general guideline only. The actual MVA and impedance values of the station service and unit auxiliaries service systems should always be used for calculating the electrical system performance of the final plant design.

4.4 Startup/Shutdown Power Supply Arrangements

Arrangement and configuration of connections selected to provide a source of power for startup/shutdown of the unit depend on various factors. Typical considerations include availability of sources, quantity and arrangement of auxiliaries buses, the number of units at a site, the proposed normal auxiliaries power supply, and equipment reliability and cost. Although power supply arrangements have been discussed in Section 3., four basic arrangements are briefly introduced to emphasize commonly-used station service system designs.

4.4.1 Auxiliaries Transformer and Generator Load-Break Switch/Generator Circuit Breaker

A load-break switch is installed in the generator leads between the unit generator and the unit auxiliaries transformer, as shown in Fig 4.1. During plant startup/shutdown, the load break switch is open, and the power supply direction is from the switchyard through the generator transformer to the unit auxiliaries transformer. When the generator comes into synchronism with the switchyard source, the generator load-break switch can be closed, thereby connecting the generator to the switchyard. No bus transfers are required, making the scheme relatively simple. One disadvantage of the scheme is that a fault on the generator leads, in the generator, or in any transformer connected to the generator leads must be cleared by the switchyard circuit breakers, thereby causing a unit blackout. Some improvement can be made by substituting a generator circuit breaker with an isolating switch for the load-break switch. The generator breaker would clear generator faults without interrupting power to its auxiliaries.

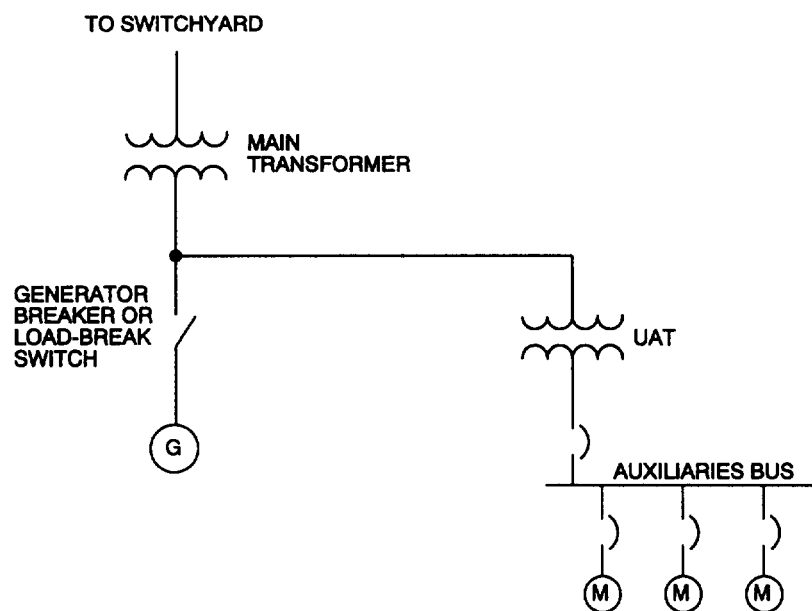


Figure 4.1 — Typical Generator Load-Break Switch or Generator Circuit Breaker Arrangement

The use of a generator load-break switch or generator circuit breaker may require special protection. If the generator is the ground source, then the system made up of the low side of the unit transformer, interconnections (bus), and unit auxiliary transformers becomes ungrounded when the switch or breaker is open. A protection scheme such as the one discussed in Section 7.3.4 for ungrounded systems should be considered.

4.4.2 Station Service Transformer

The power supply to the auxiliaries is from a station service transformer connected to the switchyard, as shown in Fig 4.2. The station service transformer supplies the auxiliaries during normal, startup, and shutdown operation. The switching of this transformer is performed by a high-voltage breaker in the switchyard. Due to the fact that loss of this transformer will leave the plant auxiliaries without power, this scheme is not commonly used. Another consideration is that any voltage disturbances on the transmission system will appear in direct proportion on the auxiliaries system.

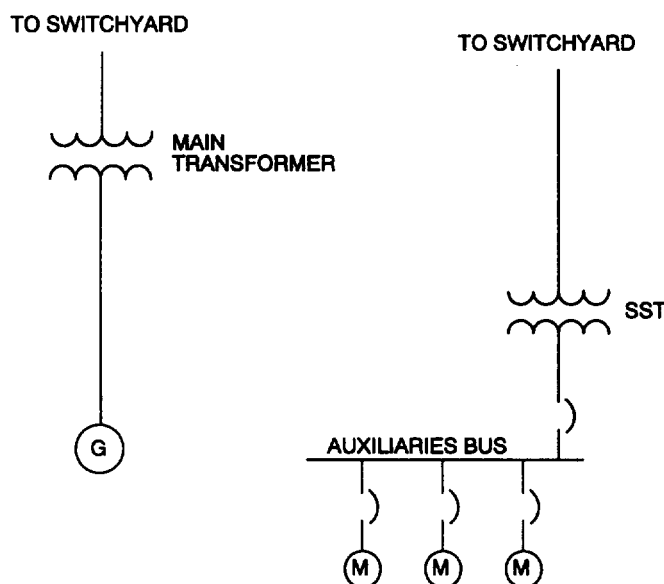


Figure 4.2 — Typical Station Service Transformer Arrangement

4.4.3 Station Service Transformer and Auxiliaries Transformer

In this scheme, which is the most common, there are two separate source connections to the unit auxiliaries bus, as shown in Fig 4.3. One connection is to the station service transformer for startup/shutdown operation. The other connection is to the unit auxiliaries transformer for normal operation. The disadvantages of this scheme are increased cost due to additional equipment, increased complexity of the relaying, and coordination required for transfer of the auxiliaries bus between the two connections. However, a dual power supply offers greater availability and reliability. Also, there will be fewer losses during plant operation because power is supplied directly from the generator to the auxiliaries bus through one transformer only. In Fig 4.2, power is supplied through more than one transformer to reach the plant auxiliaries, with correspondingly greater losses.

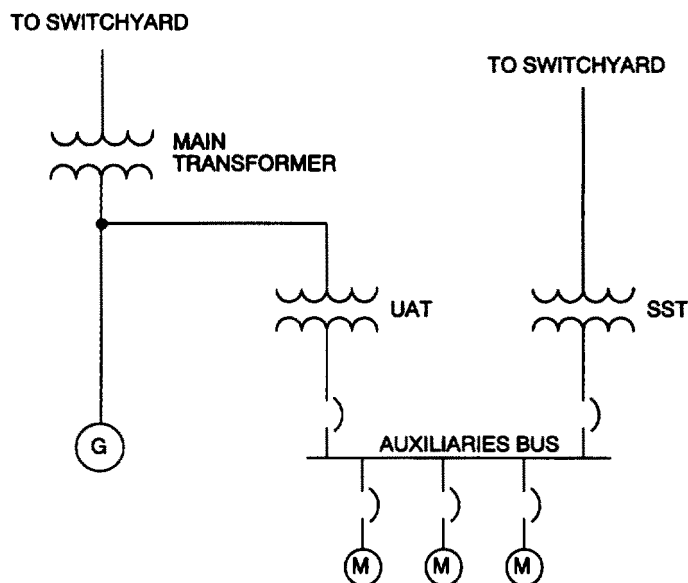


Figure 4.3 – Typical Station Service Transformer and Unit Auxiliaries Transformer Arrangement

A comparison of this scheme with the scheme that incorporates a generator breaker (shown in Fig 4.1) would be required to determine the more economical and reliable configuration. A major advantage of the above scheme may occur in multiple-unit plants if the station service transformer can be shared between units. Utilization of the generator breaker in Fig 4.1, in conjunction with using the main transformer as a startup/shutdown source for the auxiliaries, can eliminate the requirement for a station service system with its associated costs. However, during outages of single-unit plants, a smaller station source is still required for “house” loads to permit outages of the bus/cable system connecting the generator and the unit transformer.

4.4.4 Auxiliaries Transformer and Onsite Power Source

The startup/shutdown power source for the auxiliaries is an onsite source connected to the auxiliaries bus, as shown in Fig 4.4. After startup, the normal source of power to the auxiliaries is the UAT. The startup/shutdown source is usually a combustion-turbine or hydro-driven generator, supplying auxiliaries only during startup or shutdown. This scheme is not common on large units due to the size of the onsite source that would be required (i.e., auxiliaries requirements could be 10% to 12% of the unit generator output). However, in cases where the onsite source could provide an additional function, such as supplying peaking power, it may prove practical. When the above types of sources are used for startup, it should be noted that if the startup requires a large motor or a number of large motors to be started simultaneously, the size of the generator necessary should be reviewed in conjunction with the motor reactive power requirements, which will be much larger during starting.

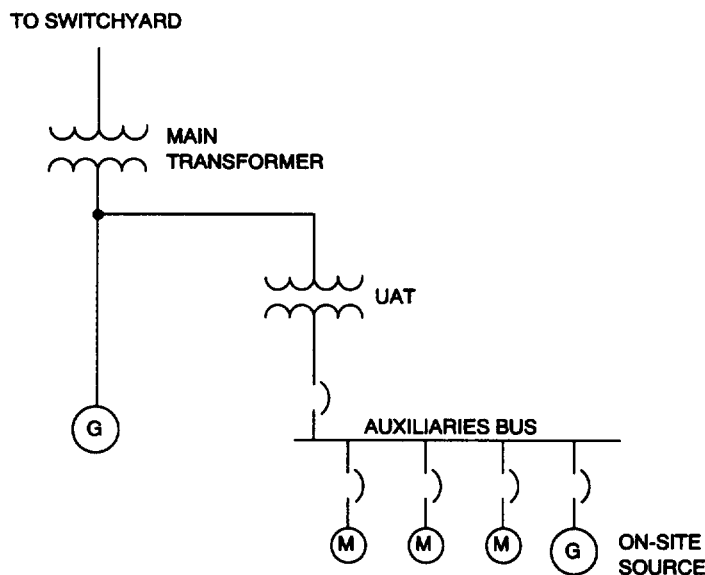


Figure 4.4 — Typical Startup/Shutdown Onsite Source Arrangement

The above scheme applies to onsite sources providing both startup and shutdown power requirements. The use of an onsite source (standby generator) to provide power to protective or emergency loads during loss of normal station power is discussed in 4.9.

4.5 Auxiliaries Equipment Supply Arrangements

In conjunction with selecting startup/shutdown power supply arrangements, proper design in the location and arrangement of auxiliaries equipment and buses will increase the safety and reliability of the system. The arrangement should include coordination of equipment requirements for both normal and startup/shutdown operation.

4.5.1 Equipment Separation for Reliability

Most units incorporate the use of duplicate and standby auxiliaries in the system design to ensure that, if one component is out of service due to failure or maintenance, its duplicate or standby will be available to allow unit operation at either full or reduced power. In addition, the use of duplicate equipment limits the supply system requirements and allows sequential starting of a series of smaller loads, which assists in bus voltage regulation. An example of duplicate or standby equipment is the use of two or three motors, each rated to carry half of the load versus one motor rated to carry the full load.

Duplicate equipment required for startup/shutdown should be served from separate buses with separate power sources or feeders, if possible. This ensures that a loss of one bus will not affect duplicate motors and equipment on the other. At the same time, duplicate loads required for normal operation should also be served from separate buses. The final design should result in multiple and relatively separate auxiliaries bus systems. The extent to which plant design will meet these criteria is dependent on evaluation of reliability gained versus added cost.

4.5.2 Equipment Separation for Protective Systems

In addition to bus separation of duplicate or standby auxiliaries loads required for both normal and startup/shutdown operation, those loads required for protective systems should also be served from separate buses or sources to achieve as much reliability as possible. Protective systems, as defined in 4.7, are those services required, especially during an unscheduled shutdown, to shut the unit down in a safe, controlled manner.

4.6 Auxiliaries Bus Transfers

During startup of the station, the unit auxiliaries bus (or buses) is typically powered from the station service system. When the unit generator has been started, partially loaded, and then synchronized with the station service system, the bus is transferred from the station service system to the unit auxiliaries system, thus obtaining its power from the unit generator. Transfer is made by closing the auxiliaries system circuit breaker, momentarily paralleling both sources, and then tripping the station service system breaker. To shut down a unit, the reverse procedure is followed. In addition to scheduled transfers during startup and shutdown, the auxiliaries bus supplying protective system loads should have the capability of being transferred to the station service system or another alternative source when there is a sustained electrical disturbance on the unit auxiliaries system. This disturbance may be due to an undervoltage condition, a fault condition, or a generator or turbine trip. A properly-designed scheme for both scheduled and unscheduled transfers will minimize both unit outage time and possible damage to equipment during transfer.

It should be noted that there may not be one “best method” of transfer, and that the transfer scheme or combination of schemes selected may require a compromise based on unique equipment requirements and conditions existing at a specific generating station.

The common types of transfers may be divided into two general categories: manual and automatic. Transfers may be categorized in other groupings, but, for purposes of this guide, this division is used with the subsequent definitions. It should be noted that the exact nomenclature of the different transfers discussed in this section may not be identical to the nomenclature used in the reference material, but the type of transfer will be readily distinguishable by its design characteristics and sequence of operation.

As an example, the transfer scheme identified as a “residual voltage transfer” in this guide is identified as a “selective time delay transfer” in [B12].

4.6.1 Manual Transfer

Manual transfer is initiated by an operator and is usually a scheduled transfer, such as during routine startup and shutdown operations. Transfer during startup is from the station service to the unit auxiliaries system. During shutdown, transfer is in the opposite direction. The transfer sequence for startup is as follows. With the station service (outgoing) source breaker connected to the auxiliaries bus, and after it has been checked for synchronism, the auxiliaries (incoming) source breaker is closed. Both sources are paralleled momentarily until the outgoing breaker is tripped. Tripping of the outgoing breaker is actuated usually by the closing of the incoming breaker and then the releasing of the breaker control switch by the operator. This method is sometimes called continuous, hot, or parallel transfer.

The major concern when paralleling both sources is fault current, which will be larger than that calculated for a single source. However, it is acceptable practice to design for the single-source condition if the duration of parallel operation is short. Many designs automatically trip the outgoing breaker after a short time delay or incorporate some type of indication to call attention to a prolonged parallel-sources condition. However, if the alternative source being paralleled is an onsite source, such as an engine-driven generator, short-circuit design calculations are usually based on this paralleled condition, if it exists for extended periods.

4.6.2 Automatic Transfer

An automatic transfer of the auxiliaries bus is initiated by relay operation in response to an electrical disturbance on the unit auxiliaries system (normal source). Both sources should be in synchronism. Transfer direction is from the normal to the alternative source. If transfer cannot be made due to a common disturbance on both sources (usually an undervoltage condition), the design may incorporate the capability of transferring the bus to an alternative onsite source. Due to the capacity of onsite sources, transfer of all bus loads may not be acceptable, and load shedding may be required. In addition to transferring without operator action, an automatic transfer differs from manual transfer because the auxiliaries bus is usually completely disconnected from either source at some time during the transfer.

If the power supply to the auxiliaries is interrupted for an extended period during the transfer, the generator unit could be affected due to lack of fuel, combustion air, control power, cooling, lubrication, etc. However, most generator unit auxiliaries can tolerate some interruption in power before shutdown conditions begin to occur. The duration of power interruption is dependent on the specific item of equipment. The limiting auxiliaries should be determined to ensure that there is no adverse effect on unit operation during the power interruption. In addition, if the voltage drops below 75% to 80% of the equipment rating during transfer, electrically-held motor starter contacts may open and interrupt power service to equipment. Motors essential to unit operation may have latched breakers or contactors so that they will not drop out during this transient condition. Sustained low-voltage conditions may also affect the torque-generating capability of the motors and may cause the loads to stall.

Automatic transfers can be classified as residual voltage, in-phase, and fast transfers.

4.6.2.1 Residual Voltage Transfer

During residual voltage or “delayed” transfer, the auxiliaries bus is disconnected from its normal source, and reconnection to its alternative source is intentionally delayed. This delay allows the “bus residual voltage” to decay to a safe value. The term bus residual voltage is used when referring to the effects of bus transfers on motors. Although this is discussed in more detail in Section 11., a definition of the term and a brief review of its effects on bus transfers are given here.

When an auxiliaries bus is disconnected from its power source, a residual voltage is maintained at the stator terminals of each motor due to the motor air-gap flux. The rate of decrease of this voltage on each motor is proportional to its open-circuit time constant which, depending on motor size and characteristics, could be 5 s or more. However, the adjacent motors on the bus will also have an effect on the individual rate of decrease, since high-inertia motors will act as generators driving the low-inertia motors. This will cause all motors on the bus to slow down at a somewhat constant rate and, due to the energy transfer between motors, will cause the individual residual voltages on all motors to decrease at approximately the same rate. The summation of individual motor voltages is the bus residual voltage. As the motors decelerate, the load angles of all motors will also increase, or slip, at approximately the same rate. The net effect is that all motors on the bus maintain some degree of synchronism. The load or torque angle referred to above is the phase displacement in electrical degrees between the bus voltage due to the source and the motor residual voltages. If the alternative incoming source voltage is connected to the bus when the residual voltage is out of synchronism with it, the total voltage impressed on the motors will be the resultant of these two vectors, which could exceed equipment rated voltage. Greater-than-rated voltages will cause larger-than-normal currents. Magnetic forces generated are proportional to the square of the current and may cause excessive forces and torques on the motor windings and shafts. Under certain out-of-phase conditions, transient torque values could exceed ten times the rated torque value.

To avoid this condition, many utilities use a residual voltage scheme when an automatic transfer is required. This scheme trips the normal source breaker upon a signal from an undervoltage relay, indicating low voltage on the normal source bus. The alternative source breaker closes on receipt of a signal from a residual voltage relay. This residual voltage relay actuates when residual voltage has decayed to a preset value. ANSI C50.41-1982 [B1] recommends allowing the residual voltage to decay to a value of 0.33 pu, which gives a resultant voltage not greater than 1.33 pu. Often a more conservative value of 0.25 pu is used.

When the residual voltage transfer scheme is used, the alternative source should have sufficient capability to repower the motors and bring them up to rated speed. During the reacceleration time after bus reconnection, all motors may be drawing close to locked rotor current and depressing the motor terminal voltages below motor nameplate requirements. In some cases, it may be required to load shed selected motors to ensure that total motor reacceleration requirements are not excessive. A review should be made of any equipment that may be affected by the momentary decrease in voltage during transfer (e.g., opening of starter and relay contacts).

This scheme is advantageous for undervoltage conditions on the normal bus caused by generator or turbine trips. If the undervoltage affected the alternative source, normal voltage should be restored by the time transfer is made.

4.6.2.2 In-Phase Transfer

In-phase transfers are made by using a phase angle and a sync-check relay. After the normal source breaker is tripped, the sync-check relay blocks the alternative-source breaker closure until the phase angle relay senses that the residual voltage and alternative-source voltage are either in-phase or within the limits of the out-of-phase condition allowed by the sync-check relay. Since both voltages will be in-phase, their resultant will not exceed the equipment voltage rating.

In-phase transfer has the advantages of making the transfer as soon as both voltages are in phase and not requiring a delay time for residual voltage decay. Consequently, this minimizes problems due to power interruption and decreases motor reacceleration time.

4.6.2.3 Fast Transfer

A fast transfer incorporates the use of fast-acting, stored-energy breakers (5 c breakers) that disconnect the normal source and reconnect to the alternative source before phase angle displacement of the bus and residual voltage can change appreciably. This ensures that the resultant voltage is not excessive. A fast transfer has no intentional time delay. The transfer is based on the assumption that the two sources are in synchronism.

Studies indicate that if the dead-bus time is kept to approximately 3–6 c, the angular displacement may not be excessive. (Dead-bus time is the term used to define the period when the bus is completely without power, i.e., after the normal source breaker trips and before the alternative source breaker closes.) For a 3 c delay, studies show the angular displacement to be 22° to 30°. Under this condition, the resultant voltage is less than rated motor voltage. For a 6 c delay, the displacement is 40° to 60°. Under this condition, the resultant voltage will be equal to or exceed motor rated voltage. Although the resultant voltage may exceed the rated voltage, it is not expected to exceed the recommended value of 1.33 pu. It should be noted that the above values of angular displacement are approximate. The electrical characteristics of the specific bus loads would have to be reviewed in conjunction with the relay and breaker operating time to ensure that the phase angle displacement of the bus residual voltage will not cause equipment damage. Many schemes allow a dead-bus time of up to 9 or 10 c. After this period, transfer is blocked.

Fast transfers should include provisions for ensuring that the two sources are in synchronism prior to transfer. A common method of ensuring synchronism is a sync-check relay, typically set for approximately 20°, that blocks closure of the bus breaker to the station service source if the phase angle difference between the station service and unit auxiliaries source exceeds this value.

Fast bus transfer may be one of three types: three-cycle, six-cycle, or parallel fast transfer.

These transfers are used during unit generator or turbine trips in which the initiating signal is the generator lock-out relay, or during fault conditions in which the initiating signal is the overcurrent relay.

4.6.2.3.1 Three-Cycle Transfer

Three-cycle transfers are initiated by the actuating relay, usually a generator lock-out relay, that simultaneously trips the normal source breaker and initiates a close signal to the backup source breaker (i.e., the backup breaker closes only if the backup source voltage is normal and is in synchronism with the normal source). The characteristics of breaker operation are such that, with a simultaneous signal, the tripping breaker will open before the closing breaker will close. This will ensure (if there is no misoperation) that two sources are not simultaneously connected to the bus. One advantage is that transfer time is too brief to allow residual bus voltage to slip significantly out of phase with the source voltage. This ensures continued operation of auxiliaries load with minimum disruption and permits shutdown of the generating unit in a more orderly manner. A disadvantage is that the operating time is so fast that should a fault occur on either source during transfer or should a fault be the cause of the transfer, and should the normal tripping source breaker remain closed to the bus or become stuck, the faulted condition may be seen simultaneously by the normal and alternative sources. This will result in an additional short-circuit contribution from the alternative source, which could overstress equipment.

4.6.2.3.2 Six-Cycle Transfer

Six-cycle transfers are initiated by the actuating relay that trips the normal source breaker. Closing of the alternative source breaker is initiated by an auxiliary “b” contact on the normal source breaker after it is open. In practice, an early “b” auxiliary contact that is faster-acting than the normal “b” contact is often used. An advantage of this scheme is that the alternative source breaker will not close until the normal source breaker is open. This assures that the two sources will not be simultaneously closed into a fault. A disadvantage is that the transfer time could exceed the safe “dead-bus” period of approximately 9 to 10 c. The delay times included in the relay protection design should be reviewed to ensure their adequacy for the transfer scheme selected.

4.6.2.3.3 Parallel Fast Transfer

Parallel fast transfers are similar to the manual transfers addressed in 4.6.1. The transfer is automatically initiated by the generator lock-out relay that closes the alternative source breaker, momentarily paralleling the alternative and normal source. An auxiliary “a” contact on this closed breaker will then trip the normal source breaker. An advantage is that there is no dead-bus time. A disadvantage is that, should a fault occur, the two sources may be simultaneously closed into it.

4.6.3 Unit Conditions During Startup/Shutdown Transfers

A detailed treatment of unit operating and loading conditions during startup is beyond the scope of this guide. However, some general observations are made to illustrate the effects on the station service system.

The auxiliaries bus (or buses) is transferred from the station service system to the unit auxiliaries system when the generator is up to rated speed and voltage, in synchronism with the power system, and when the steam/fluid conditions of the unit (e.g., pressure, temperature, flow, etc.) are within the required range. It is common practice to partially load the unit before transfer. The sequence of startup procedures to place the unit in this condition depends on individual unit characteristics. Prior to startup, some plant auxiliaries are functioning with power supplied from the station service system. They are supplied from energized distribution buses and include instrumentation and control equipment, lighting, HVAC, and communications. After these auxiliary systems are operational, the condenser cooling or circulating water system is started, followed by service water, compressed air, condensate and feed water, and, finally, the combustion air and fuel systems. Steam is then generated in the boiler, and the turbine-generator is brought to rated speed and synchronized to the power system. For large units, transfer to the normal source would occur when the unit is able to accept approximately 15% of its nameplate load rating. Smaller units would transfer in the range of 20% to 30% of rating. These percentages are general guidelines only and vary with the individual unit. As an example, large, once-through critical units may not be stable below 30% of nameplate rating, and the transfer time would be adjusted accordingly. It should be noted that auxiliaries system power required at the time of transfer is not directly proportional to unit generator output (i.e., when the unit output is 15%, the auxiliaries system power required to maintain this output is much greater than 15%, the auxiliaries system power required to maintain this output is much greater than 15% of the total auxiliaries system power requirement during normal operation). One reason for this is that many auxiliary motors will be in operation during this period, but they may be lightly loaded. In this operating mode, their power factor and efficiency will be low. Therefore, the station service system should be sized for the maximum startup/shutdown design basis requirement.

It should be emphasized that the above observations are general. The exact time of transfer is determined by both station operating procedures and the station operator, based on individual unit conditions and experience, as is the exact sequence of loading and the load requirements of the unit.

Shutdown transfer to the alternative source will be similar in the reverse direction.

4.7 Protective Systems

Protective systems function to ensure personnel safety and to protect against equipment damage. During an unscheduled or emergency shutdown caused by a unit trip, a fault condition, or the loss of both the normal and startup/shutdown sources, the requirement of continuous power is even greater for protective systems. Accordingly, an alternative or standby power supply is often provided from an onsite source that functions as a backup to the normal and startup/shutdown sources of supply to these systems. Although an exact listing of protective systems requiring this onsite source is dependent on the particular unit generator, the following are considered to be protective systems that are provided usually with at least one onsite source.

4.7.1 Turbine-Generator Auxiliaries Systems

Due to their cost and potential for damage to plant and personnel the following turbine-generator auxiliaries systems are supplied usually from an onsite source.

4.7.1.1 Lubrication System

Large turbine-generator bearings require continuous forced lubrication and water cooling during both operation and coastdown, and may be damaged if this is interrupted while the shaft is still rotating. In addition, bearing damage could decrease the clearances between the rotating and stationary elements and result in further damage. After a unit is shut down, it must continue to be rotated to assure uniform cooling in order to prevent thermal bowing (eccentricity) of the rotating element.

For a typical unit, lubrication motors consist of the following:

- 1) Shaft-driven main bearing oil pump (MBOP)
- 2) AC motor-driven turbine bearing oil pump (TBOP)
- 3) DC emergency bearing oil pump(s) (EBOP)

The shaft-driven main bearing oil pump is mounted on the turbine shaft and delivers lubricating oil during normal operation. During startup and shutdown, the ac oil pump motors supply oil when the main shaft-driven pump is not up to pressure. These ac motors are backed up by the dc emergency bearing oil pump, which is fed from a station battery and started automatically on low oil pressure. A second backup dc pump is sometimes provided. Lubrication motors may also include the bearing lift pump motors (some large units cannot be placed on turning gear without the lift pumps running) and the turning gear oil pump motor.

4.7.1.2 Hydrogen Seal System

Hydrogen is often used as a coolant for large generators because its heat transfer and electrical properties are superior to nonexplosive gases. High-purity hydrogen will not support combustion. However, when mixed with air to a level of 95% purity, it is considered explosive. Therefore, a sealing system must be provided to prevent the hydrogen gas from escaping the generator casing. This is done by maintaining pressure on an oil seal around the generator shaft. As long as the oil pressure is greater than the hydrogen gas pressure, a seal will be formed confining the gas inside the generator and preventing leakage to areas outside the casing.

For a typical unit, the seal oil motors would consist of the following:

- 1) AC main seal oil pump (MSOP)
- 2) DC emergency seal oil pump (ESOP)
- 3) AC motor-driven vacuum pump

The main seal oil pump is used normally and is backed up by the dc emergency seal oil pump, which is fed from the station battery. These pumps circulate oil through the seals while the vacuum pump removes the hydrogen from the oil

in the hydrogen drain tanks. Some vendors will furnish two main seal oil pumps instead of one. These two pumps, one for each side of the seal, are called the air-side and hydrogen-side seal oil pumps.

4.7.2 Burner Management Systems

Fossil-fueled steam generators must be designed so that the fuel supply will be interrupted if there is a loss of water supply. Otherwise, fired metal parts under steam pressure could become overheated, due to lack of cooling, causing failure or explosion. In addition, loss of ignition at the burners will result in unignited fuel being injected into the steam generator furnace, which could result in an explosion if the fuel were ignited either from hot metal parts from or accidental initiation of the burner system. To ensure that the fuel supply is interrupted, automatic controls (burner management systems) are provided that continuously monitor burner ignition, fuel, air, and water supply and that interrupt power to the supply valves when a hazardous condition is detected. To provide assurance that the system will always fail-safe, the control valves, dampers, and feeder breakers should be energized continuously in the operating position or should have the required control circuitry so that they will automatically close and shut down the unit upon loss of control power. Therefore, they require a continuous source of power.

4.7.3 Electrical Protection Systems

A source of electrical power for closing and tripping power supply breakers and for relays is provided usually from an onsite source, because lack of control power for these devices could result in damaging electrical conditions such as short circuits, overcurrents, and undervoltages remaining on the electrical system. In addition, many circuit breakers are latched mechanically so that they will remain closed for transient fault conditions. These breakers require an onsite source for tripping when all power is lost. These devices can be obtained for operation on either ac or dc power. Control power for switchgear breakers in generating stations is normally from the station battery.

4.7.4 Instrumentation and Control Systems

Due to the increasing use and reliance on instrumentation and control devices in generating plants, most devices that control or monitor protective systems will be connected to an onsite source of power. Included in this category would be plant computers or other devices that cannot tolerate an interruption in power and that must function to assure that data is collected during fault and transient conditions.

4.7.5 Miscellaneous Systems

Miscellaneous systems requiring an onsite source are those systems not usually required for operation of the auxiliaries, but which may be required when normal power is lost, such as fire protection, elevators, battery chargers, HVAC, and emergency lighting systems.

4.8 DC, DC/AC, and AC/DC Power Sources

To ensure a reliable source of dc power to dc protective equipment and systems, an onsite dc source is normally provided in the generating station. DC loads are supplied continuously from this onsite source and, with suitable isolation and suppression devices, are essentially independent of the station service and unit auxiliaries system. These sources are used where power requirements are relatively small and of short duration. The supply is generally considered to be uninterruptible.

Onsite dc power sources usually consist of two main components: the storage battery and its associated battery charger. This combination provides the high reliability that is attributed to dc power supplies.

Also included is an item of equipment generally associated with the battery and charger, the inverter, which is powered from the dc source but supplies ac power. These three components, when combined, provide an un-interruptible power system (UPS) that furnishes a continuous, highly-reliable source of ac supply.

In this section, a brief description of motor-generator (M-G) sets is also included since these are used, in special circumstances, as a UPS.

4.8.1 Storage Battery

The battery charger normally provides power to protective equipment and systems that cannot tolerate a power interruption and also normally provides a trickle charge to the battery. Therefore, the battery is normally maintained at full charge and is available continuously to provide power to the system.

Battery use is standard for most generating units to supply all dc powered equipment, including motors, instrumentation and control (including circuit breaker controls), alarms, emergency lighting, and UPS. The reliability of service may be reduced by the aging characteristics of the batteries. However, when properly tested and maintained, and when used in conjunction with a battery charger, the battery is regarded as the most reliable power source in the generating station. In addition, when an inverter is added, an extremely reliable source of ac power is also provided.

4.8.1.1 Battery Types and Construction

The most common type of battery used in generating stations is the lead-acid type. Two different classes of the lead-acid type of station battery are the lead-calcium and lead-antimony. The term “lead” defines the major component of the plate material, and the terms “calcium” and “antimony” define the additives used with the lead that give the specific type of battery its unique characteristics. For example, the lead-calcium type generally has a longer life than lead-antimony, but it costs more. These additives may be included either in the plate material or in the surrounding grid that supports the plate material.

Each set of plates (one set positive and one set negative), with its supporting grid and connectors, is called a cell. The composition and configuration of the plate and grid material determine one of the two basic characteristics of the battery, the voltage per cell.

4.8.1.2 Voltage Rating

The basic battery unit is the cell. One of the two primary electrical characteristics of each battery cell is its volts per cell. The nominal voltage on a lead-acid cell is approximately 2.05 V per cell. Connection of these cells in series furnishes the standard battery voltages required for dc equipment operation. For a 60-cell battery with a nominal rating of 2.05 V per cell, the nominal output voltage would be 125 V dc.

The dc equipment powered by the battery must be specified to operate within the design battery voltage range, which is typically 2.33 to 1.75 V per cell. For a 60-cell battery, this corresponds to a battery terminal voltage of 140 V to 105 V dc, respectively. This minimum value of 105 V dc is the battery terminal voltage at the end of the discharge cycle and does not include the voltage drop in the cable connecting the load to the battery. Since batteries are generally located in one central location, loads that are relatively distant from the battery may have appreciable cable resistance voltage drop, which may require oversized feeder cables. A typical design may specify dc equipment to be suitable for operation at 101 V dc. This would allow a feeder voltage drop of 4 V. In some systems, a lower limit of 90 V dc may be selected, but only equipment rated at this lower voltage should be used. For example, 90 V dc would be an acceptable control voltage for most breakers but would not be satisfactory for dc motors. Prolonged operation of equipment at too high a voltage may also be damaging. This problem is due primarily to specifying too narrow an equipment voltage range or operating the battery charger at too high a voltage, resulting in overheating of the equipment and degradation of its insulation.

In general, 60-cell batteries (125 V dc nominal) are used in most stations. In some stations, where large dc motors are required, or where the feeder voltage drop is excessive, 120-cell batteries (250 V dc nominal) also may be used. Large dc motors are used often in the turbine-generator auxiliaries system (see 4.7.1). In situations in which both ratings of battery are used in a station, the 250 V dc will usually supply only large loads, and the 125 V dc will supply small motor loads and instrumentation and controls. Less frequently, 48 V or 24 V dc systems are used.

4.8.1.3 Ampere-Hour Rating

The second primary electrical characteristic of the battery is its ampere-hour (Ah) capacity, which is a measure of its ability to supply specified loads for a certain time period (discharge period). To be acceptable for critical applications, the battery must be capable of supplying the required amperes at the minimum specified voltage at all times during its discharge period. A standard procedure for calculating this capability is provided in IEEE Std 485-1983 [B5]. Using this procedure, the required dc loads are tabulated with respect to magnitude and duration. This tabulation establishes a load vs. time profile that is called a “duty cycle.” Using this duty cycle and using manufacturer’s curves that show the Ah capacity at a specified discharge rate, the required battery capacity may be calculated. The capacity requirements may be reduced if loads are connected to the battery in a certain sequence, for example, if controls are provided to assure that large dc motors are not started simultaneously. Typical station batteries range from 200 to 4000 Ah with typical discharge rates of either 2, 3, or 8 h. The storage capacity of the battery is dependent on the type, construction, operating temperature, rate of discharge, and age of the battery. Although most batteries will show increased capacity for a short time after initial use, all batteries will have decreased capacity with increasing age.

The capacity of the battery, since it is an electrochemical device, is affected directly by its temperature. Battery capacity is usually given assuming a battery temperature of 25 °C (77 °F). For higher temperatures, capacity may be increased; for lower temperatures, capacity will be reduced. At 0 °C (32 °F), the capacity may be reduced to approximately 70% of its normal rating at 25 °C (77 °F). However, higher ambient temperatures decrease battery life, even though capacity may be increased. For this reason, rooms dedicated to the station batteries may require special consideration to maintain proper temperatures.

4.8.1.4 Testing and Maintenance

Periodic battery testing and maintenance is usually done to ensure acceptable capacity and voltage and to identify potential problems. IEEE Std 450-1987 [B3] provides procedures and recommends replacement criteria. It should be noted that these criteria should be applied to allow sufficient time for battery replacement, since there must be reserve capacity at the time of the periodic test to ensure that the battery will continue to supply its design requirements until it can be replaced.

4.8.2 Battery Charger

The battery charger functions in conjunction with the battery. It is the combination of these components that provides the high degree of reliability exhibited by dc onsite sources. The modern static battery charger incorporates solid-state components and functions as a rectifier. Its ac input power is rectified into dc output power.

The charger is operated usually in parallel with the battery. During normal operation, the charger will supply the dc loads and maintain the battery in a properly charged condition. During abnormal or emergency conditions in which the dc load is high, the battery will assist in powering loads that are beyond the capability of the charger. It should be noted that when the charger is used to provide a direct supply for dc loads, this requirement should be specified in order to incorporate the necessary filtering. Chargers that do not power dc loads do not require additional filtering. This would be the case in which a charger was used only to charge the battery or supply an inverter. To ensure that power for the dc loads will be adequate, the charger is sized to supply the normal dc load while simultaneously recharging the discharged battery in a specified time period. In addition to powering normal dc load, the charger must “charge” or furnish charging current to the battery to ensure the battery is maintained at full charge or capacity. Battery charging is done by operating the charger in one of two modes: the “floating” mode or the “equalizing” mode. The floating mode is used for normal day-to-day charging and maintains a voltage on the battery slightly higher than the battery open-circuit voltage. The approximate float voltages for lead-acid type batteries are 2.15 to 2.20 V per cell for antimony and 2.17 to 2.25 V per cell for calcium types.

The equalizing mode maintains a higher voltage on the battery than the float voltage and is used to bring all cells up to the same charge. This is done because, at floating voltage, charging current is so small that voltage differences in the various cells may exist. The equalizing charge will be done usually at some periodic interval, usually monthly. The floating charge is usually applied continuously. The equalizing charge also will be given usually after the battery is

discharged. A typical equalizing voltage for lead-acid types would be about 2.33 V per cell. It should be noted that 2.33 V per cell corresponds to a maximum 60-cell battery voltage of 140 V, which is usually the maximum specified voltage rating for dc equipment. In most cases, this rating imposes the maximum voltage at which the battery may be equalized. The above voltage values for floating and equalizing are approximate only and should be verified with the manufacturer for the specific equipment used. The charger is supplied usually from an auxiliaries bus that can be powered from the onsite ac power source for increased reliability.

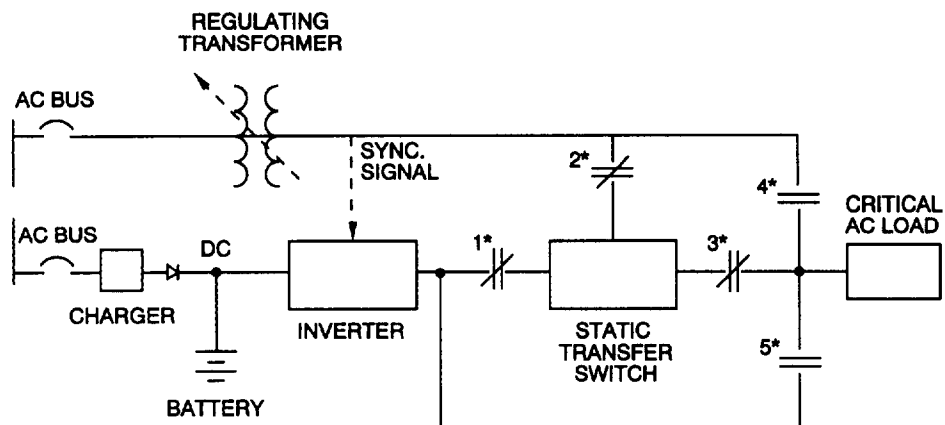
4.8.3 Inverter

Inverters supply a regulated source of ac power to protective and critical loads. Normally, they are supplied dc input from a charger or rectifier, with the battery as its backup source. Most inverters are static devices using transistors and silicon controlled rectifiers (SCR's) to develop an alternating wave form from the dc power source. Inverters have load-limiting controls and filtering circuits to reduce transient voltages and may incorporate redundant components to increase reliability.

4.8.4 Uninterruptible Power Supply

An uninterruptible power supply (UPS) provides a highly reliable, uninterruptible source of voltage and frequency-regulated ac power. Typical loads supplied are instrumentation, control, computers, and electronic circuits that require an extremely reliable source. The transient voltage conditions caused by the transfer schemes discussed in earlier sections will generally have minimal effect on most auxiliaries such as motors or heaters. They could, however, cause misoperation of voltage and frequency-sensitive devices and loads. In addition, the functioning of the auxiliaries themselves, such as the starting of large motors, causes transients that may affect these circuits unless they have some electrical transient protection or isolation from both the startup/shutdown and normal source. Protection and isolation are incorporated usually in the UPS.

The static UPS (as distinguished from a UPS provided by motive power) is an integrated assembly of the components discussed above and includes a charger, a battery, and an inverter. In addition, the UPS also includes a static bypass switch (static switch) and a manual bypass switch. The usual configuration is shown in Fig 4.5: the charger or the battery is supplying the inverter which in turn powers the ac loads. The static switch is located on the inverter output. In the event of loss of inverter output or inverter malfunction, the switch will transfer the loads to an alternative ac source. This source is provided sometimes through a voltage-regulating transformer to ensure a well regulated voltage source for the loads. Circuitry is provided in the UPS to maintain it in synchronism with the alternative source. The transfer can be made in milliseconds, usually with negligible effects on the loads. The manual bypass switch is used normally to connect the loads to the alternative source when the UPS is removed for maintenance. The switch is typically a "make before break" type.



*THREE POSITION MANUAL BYPASS SWITCH					
CONTACT NO.	1	2	3	4	5
SWITCH POSITION					
NORMAL	x	x	x		
STATIC SWITCH BYPASSED					x
UPS SYSTEM BYPASSED				x	

x INDICATES CONTACT CLOSED

Figure 4.5 – Typical Static UPS Arrangement

All components are bought usually as one integrated package, and the UPS is termed as being a “dedicated” power supply (i.e., it feeds only one specific load or type of load). Included in this package are controls and indicating device accessories, including provision for manual and/or automatic transfer of the power supply. For situations in which redundant loads are present, the loads would be segregated and each would be supplied by a separate UPS.

In generating units, UPS requirements are small in comparison to most auxiliary loads and usually do not exceed 150 kVA.

4.8.5 Motor-Generator Set

The motor-generator (M-G) set, as shown in Fig 4.6, is the predecessor of the static UPS system described in 4.8.4 and is generally used only in specific applications. The M-G set may be either ac/dc or dc/ac.

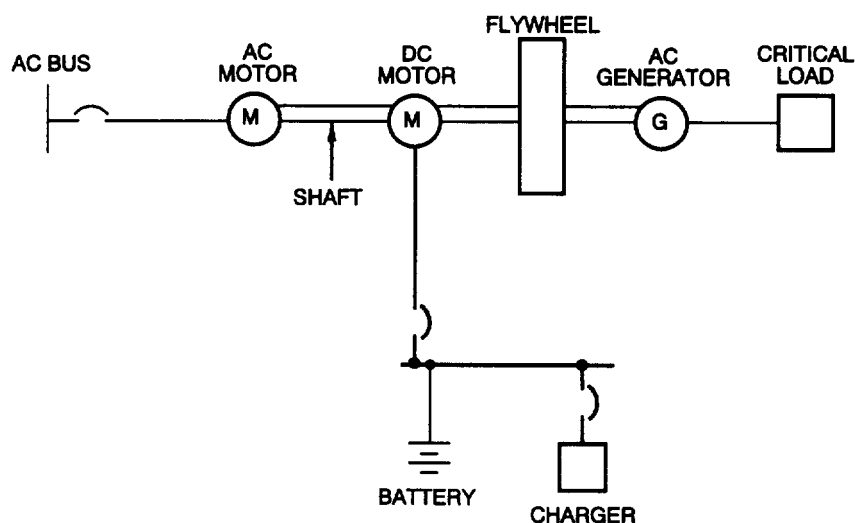


Figure 4.6 — Typical AC/DC/AC Motor-Generator Set Arrangement

The basic components of the ac/dc set are an ac generator, an ac motor, a dc motor, and, sometimes, a flywheel. The components are direct-connected, in-line, with flexible couplings, and mounted on a common base. During normal operation, the ac motor provides motive power to the generator through the shaft, which powers a critical load. When the power source to the ac motor is lost or degraded, the power source to the ac motor is automatically disconnected, and the dc motor is automatically energized by the battery providing motive power to the generator. The inertia of the flywheel powers the generator shaft while the ac source is being disconnected and the dc source is being connected.

The dc/ac M-G set is shown in Fig 4.7. The basic components of the set are a dc motor and an ac generator. The dc motor provides motive power to the generator, which powers a critical load. The dc motor is powered by a rectifier/charger during normal operation, with a battery as an alternate source.

The advantages and disadvantages of the different schemes should be reviewed with regard to cost, reliability, and maintenance.

4.9 Onsite AC Power Sources

In addition to the onsite dc source, an onsite ac source is usually provided in larger units to furnish an alternative supply to ac protective systems and loads in the event of loss of the station service and unit auxiliary system. These onsite sources, which are standby generators, are used for larger, sustained (greater than 2 h) load requirements and will often serve as a long-term backup for the battery and UPS systems. These alternative sources usually do not provide continuous power, since they are only connected to the bus upon loss of the station service or unit auxiliaries system. In addition, they require a time period before they are up to rated speed and voltage and able to accept load.

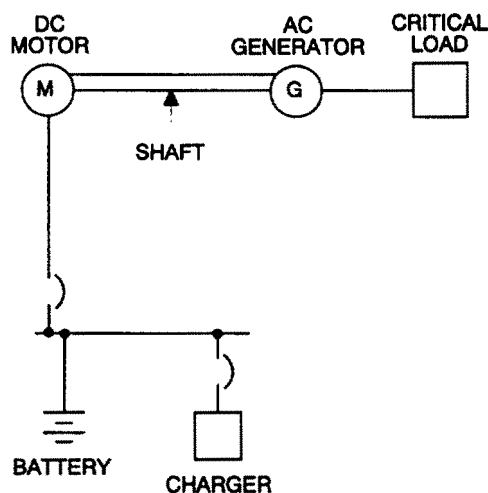


Figure 4.7 — Typical DC/AC Motor-Generator Set Arrangement

The standby source must be highly reliable, have a fast starting capability, and be able to accelerate and carry the required auxiliary load until either the unit is in a safe shutdown condition, the startup/shutdown source is restored, or the unit generator is again available to power the auxiliaries. A prime requirement for standby generators supplying protective systems is that the standby generators be started and able to supply power as quickly as possible. In many cases, the total auxiliary loads will be too large to be picked up by the generator at one time, and the generator will be loaded sequentially.

Normally, standby generators are not operated in parallel with the station service or unit auxiliaries system, except for testing or as previously noted in 4.4.4. Two reasons for not using this mode of operation are the higher fuel and maintenance costs and the exposure of the standby generator to electrical faults on the normal power system.

Operation in this mode could result in a degradation of the reliability of the standby generator.

The prime mover for a standby generator can be either an engine (diesel, gasoline, or gas) or a turbine (gas, steam, or hydraulic).

4.9.1 Diesel-Engine Generators

A diesel-engine generator, automatically started, is used most often as an ac standby source at a generating station. This is due to its characteristics of low installation and maintenance cost, use of nonvolatile fuel, and quick starting time (less than 10 s). In addition, diesel engines, especially the lower-speed models, are applied often as long-term sources of continuous power. Equipment output ratings are given for operating times of up to 8000 h duration, and units are available in sizes from 1 kVA to several thousand kVA.

The starting reliability of diesel engines may be significantly improved by maintaining the engines and fuel at an elevated temperature [15.5 to 40.5 °C (60 to 105 °F)].

The load pickup characteristics of the generator and the diesel engine should be selected in accordance with the design loads and the sequence in which they will be energized. Voltage transients when energizing loads should be limited generally to +15% and -25% of the machine's rating. Transients that exceed these limits may cause dropout of motor starters and stalling of motors. Frequency transients should not exceed $\pm 5\%$ of rated frequency to maintain adequate pressure and flows in the powered equipment.

On larger units, as noted in 4.6, the typical application of the diesel engine generator is as an alternative source. After loss of the unit auxiliaries or station service system source, or both, the standby generator would be given a start signal (usually due to a persistent undervoltage on the bus), and the normal source breaker would open. The standby source breaker would then close to the bus after the generator is at rated speed and voltage. In most cases, starting and supplying the total bus load would exceed the engine-generator's capability. For these cases, it is a usual practice to develop a "diesel-generator loading schedule," which is a listing of the loads, their ratings, and the sequence in which they will be repowered. Since most motor loads will be in a starting condition, their power factors will be low, and it should be determined that the KVAR capability of the generator is adequate. In general, each different load or groups of loads will be sequenced on the diesel generator with sufficient time between loading intervals to allow for voltage restoration by the regulator. As previously stated, the voltage dip, in general, should not exceed 25%. Where required, the adequacy of a specific engine-generator for the loading schedule should be reviewed with the manufacturer.

4.9.2 Gasoline and Gas-Engine Generators

Gasoline and gas-fueled engines, although similar to diesel engine generators in their electrical output characteristics, are not usually selected for standby source application because of the hazards associated with supplying volatile fuels. However, when storage and safeguards for volatile fuels are in place for other reasons (i.e., a gas-fired steam generator or gas ignition for pulverized fuel burners), a gas engine or gas turbine may be selected. These engine-generators are not as quick starting as diesels, and they require a longer interval between start time and the time they are able to be loaded. A typical time may be from 30 to 90 s. They are available typically in sizes up to 600 kW.

4.9.3 Turbine-Driven Generators

Noncondensing steam turbines are very reliable, but they require a reliable source of steam when the main steam generators are not available. This is not economical unless the required boilers are in service for other reasons.

Hydraulic turbines may be used when there is a source of hydropower near the station. If long and exposed transmission lines are required for transporting the hydropower, the unreliability due to the lines may not be acceptable.

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5. Nominal System Voltage

5.1 Introduction

The nominal voltage of an electric power service system is the approximate midpoint of voltage within which the system is intended to operate. Utilization equipment manufactured to industry standards is expected to perform satisfactorily, with long life, when operated within certain voltage limits.

Factors that effect the selection of nominal voltage levels for the service system are

- 1) Type and size of load to be served
- 2) Distance power is to be transmitted
- 3) Future load growth
- 4) Equipment available for fault isolation
- 5) Permissible voltage regulation
- 6) Cost of utilization and service system equipment

Standard preferred-voltage ratings of distribution and utilization equipment limit the available voltage selection throughout the power service system. Analysis of characteristics, costs, and capabilities of the available equipment determine voltage levels that permit satisfactory operation and protection of power supply buses under all conditions.

A typical auxiliaries power supply system and associated components for a single-unit generating station are shown in Fig 5.1.

5.2 References

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⁷NFPA publications are available from Publications Sales, National Fire Protection Association, 1 Batterymarch Park, P.O. Box 9101, Quincy, MA 02269-9101, USA.

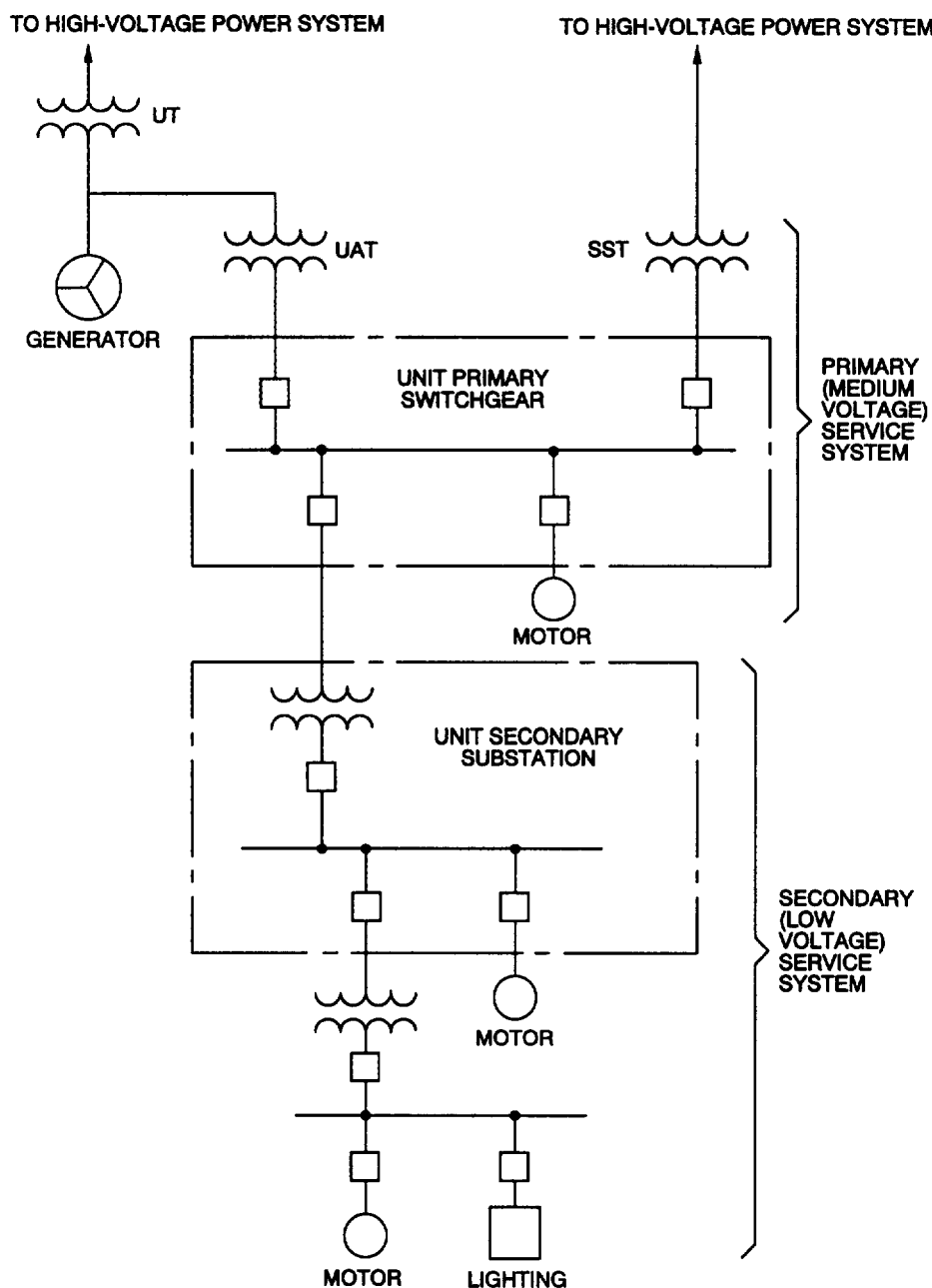


Figure 5.1 — Simplified Auxiliary Power Service System Single-Line Diagram for a Single-Unit Generating Plant

5.3 Definitions

nominal system voltage: The rms phase-to-phase voltage by which the system is designated and to which certain operating characteristics of the system are related. The nominal system voltage is near the voltage level at which the system normally operates.

service voltage: The nominal voltage at the generating station service buses.

utilization voltage: The voltage at the line terminals of the utilization equipment.

equipment rated voltage: The voltage, marked on the equipment nameplate, to which the equipment operating and performance characteristics are referred.

5.4 Preferred Nominal System Voltages

The standard for electric power system voltages in the United States is ANSI C84.1-1989 [1].⁸ This standard lists the standard nominal system voltages and acceptable operating ranges. These nominal voltages are summarized in Table 5.1. Voltages with an asterisk next to them are utilized most commonly in generating stations.

5.5 Acceptable Voltage Ranges

Proper design of the electrical auxiliaries system requires that acceptable voltages be maintained at the utilization equipment.

ANSI C84.1-1989 [1] specifies various ranges of service voltage and utilization voltage for typical industrial and commercial power systems. These ranges may also be used as a guide in the design of generating station electrical service systems.

The ANSI C84.1-1989 [1] ranges usually must be extended to allow for the special requirements of generating station operation, such as the ability to vary unit generator voltage in response to needs of the high-voltage bulk transmission system. This unit generator voltage variation (95% to 105%) has a direct impact on the electrical auxiliaries system voltage regulation because the unit auxiliaries transformer is usually connected directly to the generator bus. Operation of the unit generator must not be constrained by undue restrictions on voltage regulation of the electrical auxiliaries system. As a result, voltage ranges are established usually to take maximum advantage of the capability of utilization equipment to operate under voltage extremes. In some instances, motors or other equipment may be specified with voltage tolerance capabilities outside of the standard ranges.

⁸The numbers in brackets correspond to the references in Section 5.2.

Table 5.1 — Nominal Auxiliaries System Voltages

		<u>Single Phase</u>	
		120	2 Wire
		120/240	3 Wire
		<u>Three Phase</u>	
		208Y/120*	4 Wire
Low-Voltage System 0 to 1000V		480Y/277*	4 Wire
		480*	3 Wire
		600	3 Wire
		2400*	3 Wire
		4160/2400	4 Wire
Medium-Voltage System 1000 to 72 500 V		4160*	3 Wire
		4800	3 Wire
		6900*	3 Wire
		13 800*	3 Wire

NOTE — For a more complete list, see ANSI C84.1-1989 [1].

*Voltages most commonly utilized in generating stations

In generating station applications, it is usually considered acceptable to exceed equipment voltage tolerances during some short-term plant operating conditions. This is primarily due to the high level of instrumentation found in generating stations that permits close monitoring of auxiliary equipment. To a lesser extent, these short-term voltage excursions are more acceptable in generating stations because the utility itself is the user, rather than a retail customer, and there are no legal obligations to maintain voltage levels.

If the steady-state system voltage regulation must be increased, it may be more desirable to skew the system voltage toward overvoltage rather than undervoltage. This is because overvoltage will normally occur during light load conditions of the generating station, which should be of shorter duration and less frequent than normal load conditions. Undervoltage will generally cause reduced performance of the auxiliary equipment. Since undervoltage will usually occur during high plant loading when maximum auxiliaries are required, a loss of auxiliaries performance may not be tolerable.

Transient voltage regulation during starting of large motors in generating stations is usually well outside the voltage ranges established by ANSI C84-1989 [1]. System designs that permit transient voltage dips to 75–80% are not uncommon and are usually quite acceptable in generating station applications. The primary consideration during these extreme motor starting dips is the dropout voltage of relays and contactors rather than the effect on auxiliary equipment.

5.6 Equipment Ratings

Table 5.2 indicates the standard voltage ratings of service and utilization equipment in relation to nominal system voltage. When discussing utilization equipment, rated voltage should be used because it is the voltage to which operating characteristics are referred. Rated voltage of utilization equipment is generally lower than nominal system voltage. The voltage rating of service equipment (generators, transformers, and switchgear) is generally higher than the voltage rating of the utilization equipment and is usually equal to nominal system voltage. The difference between rated voltage of service and utilization equipment allows for voltage regulation of the distribution system.

Table 5.2 — Basic Pattern of Voltage Identification

Service Equipment			Utilization Equipment		
Nominal System Voltage	Transformer Primary Rated Voltage	Transformer Secondary Rated Voltage	Motor Rated Voltage	Lamp Rated Voltage	Solenoid and Relay Rated Voltage
Single Phase					
120/240	240	120/240	115, 230	120, 240	120, 240
Three Phase					
208Y/120	208, 120	208Y/120	200	208, 120	208, 120
480Y/277	480	480Y/277	460	277	480
600	600	600	575		
2400	2400	2400	2300		
4160	4160	4160	4000		
6900	6900	6900	6600		
13800	13800	13800	13200		
Direct Current					
125			120	120	125
250			240		

5.7 Effects of Voltage Variation in Utilization Equipment

5.7.1 General Effects

When the voltage at the terminals of utilization equipment deviates from the value on the nameplate of the equipment, the performance and the operating life of the equipment are affected. The effect may be minor or serious, depending on the characteristics of the equipment and the amount of the voltage deviation from the nameplate rating. Generally, performance conforms to the utilization voltage limits specified in ANSI C84.1-1989 [1], but it may vary for specific items of voltage sensitive equipment.

5.7.2 Induction Motors

The variation in induction motor characteristics as a function of the applied voltage is given in Table 5.3. Motor voltages below nameplate rating result in reduced starting torque and increased full-load temperature rise. Motor voltages above nameplate rating result in increased torque, increased starting current, and decreased power factor. The increased starting torque will increase the accelerating force on couplings and driven equipment. Increased starting current causes greater voltage drop in the supply circuit and decreases the voltage on other connected equipment. In general, voltages slightly above nameplate rating have a less detrimental effect on motor performance than voltages slightly below nameplate rating. However, voltages higher than 110% of rated voltage may saturate the stator iron, thereby increasing the fundamental and harmonic components of exciting current and losses by many times. This increased excitation loss will result in higher motor temperature. Greater than normal voltage regulation may be acceptable under reduced load or lower ambient temperature conditions.

Table 5.3 — Effect of Voltage Variation on Induction Motors (Typical)

Characteristic	Approximate Function of Voltage	90% Voltage*	110% Voltage*
Starting and maximum running torque	V^2	Decrease 19%	Increase 21%
Percent Slip	$1/V^2$	Increase 20–30%	Decrease 16–24%
Efficiency Full load	—	Decrease 0–1.5%	–2% to +0.5%
3/4 load	—	–0.2% to +1%	Decrease 0.1–4%
1/2 load	—	Increase 0–3%	Decrease 0.5–6%
Power Factor Full load	—	Increase 0.5–5%	Decrease 2–8%
3/4 load	—	Increase 2–7%	Decrease 6–10%
1/2 load	—	Increase 4–10%	Decrease 9–12%
Full load current	—	Increase 5–11%	+4% to –7%
Starting current	V	Decrease 10–12%	Increase 10–12%
Temperature rise	—	Increase 5–20%	+5% to –8%
Maximum overload capacity	V^2	Decrease 19%	Increase 21%
Magnetic noise	—	Slight decrease	Slight increase

*There may be wide variations depending upon the type of motor, such as dripproof (DP) or totally enclosed fan cooled (TEFC), and horsepower rating, with smaller ratings showing the greater variations. Some data will vary according to manufacturers.

The minimum motor terminal voltage during starting is limited only by the accelerating torque requirements and the thermal capability of the rotor. Voltage dips to 75% or less may be permissible if these criteria are satisfied.

5.7.3 Synchronous Motors

Synchronous motors are affected in the same manner as induction motors, except that the speed remains constant (unless the frequency changes), and the maximum or pull-out torque varies directly with the voltage if the field voltage remains constant, as in the case in which the field is supplied by a generator on the same shaft with the motor. If the field voltage varies with the line voltage, as in the case of a static rectifier source, then the pull-out torque varies as the square of the voltage.

5.7.4 Incandescent Lamps

The light output and life of incandescent filament lamps are affected significantly by voltage. The variation of life and light output with impressed voltage is shown in Table 5.4. The figures for 125 V and 130 V lamps are also included because these ratings are useful where long life is more important than light output, such as in displays, safety lighting, etc.

5.7.5 Fluorescent Lamps

Fluorescent lamps operate satisfactorily over a range of $\pm 10\%$ of the ballast nameplate rating. Light output varies approximately in proportion to the applied voltage. The life of fluorescent lamps is affected less by voltage variation than is the life of incandescent lamps.

Table 5.4 —Effect of Voltage Variations on Incandescent Lamps (Typical)

Applied Voltage (V)	Lamp Rating					
	120V		125V		130V	
	Percent Life	Percent Light	Percent Life	Percent Light	Percent Life	Percent Light
105	575	64	880	55	—	—
110	310	74	525	65	880	57
115	175	87	295	76	550	66
120	100	100	170	88	280	76
125	58	118	100	100	165	88
130	34	132	59	113	100	100

The voltage-sensitive component of the fluorescent fixture is the ballast. It is a small reactor or transformer that supplies the starting and operating voltages to the lamp and limits the lamp current to design values. Ballasts may overheat when subjected to above-normal voltage. Integral thermal protection may be provided as a safeguard. See ANSI/NFPA 70-1990, Article 410 [2].

5.7.6 High-Intensity Discharge Lamps

Mercury, sodium, and metal halide lamps using a conventional unregulated ballast have a 30% decrease in light output for a 10% decrease in terminal voltage. If a constant wattage ballast is used, the decrease in light output for a 10% decrease in terminal voltage will be about 2%.

Mercury lamps require 4 to 8 min to vaporize the mercury in the lamp and reach full brilliancy. At about 20% undervoltage, the mercury arc will extinguish, and the lamp cannot be restarted until the mercury condenses. This takes 4 to 8 min unless the lamps have special cooling controls. Lamp life is inversely related to the number of starts. If low-voltage conditions require repeated starting, lamp life will be significantly reduced. Excessively high voltage raises the arc temperature, which may damage the lamp enclosure if the temperature approaches the glass-softening point. Sodium and metal halide lamps have characteristics similar to those of mercury lamps. See the manufacturer's catalogs for detailed information.

5.7.7 Infrared Heating Process

Although the filaments in the lamps used in these installations are of the resistance type, the energy output does not vary with the square of the voltage because the resistance varies at the same time. However, the energy output does vary roughly as some power of the voltage slightly less than the square. Voltage variations are usually of minor importance because the heat output is generally regulated by automatic control.

5.7.8 Resistance Heating Devices

The energy input and, therefore, the heat output of resistance heaters varies, in general, with the square of the impressed voltage. A 10% drop in voltage will cause a drop of 19% in heat output for an operating range over which the resistance remains essentially constant. However, automatic regulation usually makes such variations unimportant.

5.7.9 Electron Tubes

Electron emission of all electron tubes is affected seriously by voltage deviation from rating. The cathode life curve indicates that the life is reduced by half for each 5% increase in filament voltage. This is due to the reduced life of the

heater element and to the higher rate of evaporation of the active material from the surface of the cathode. It is extremely important that the filament voltage be kept near rating for satisfactory service. In many cases, this will necessitate a regulated power source. This power source may be located at or within the equipment and often consists of a regulating transformer having constant output voltage or current.

5.7.10 Capacitors

The reactive power of capacitors varies as the square of the impressed voltage. A drop of 10% in the supply voltage reduces the reactive power by 19%. Where an investment in capacitors for power factor improvement is made, the benefit of almost 20% of this investment is lost. Conversely, at 110% voltage, the reactive power of the capacitors is 21% above rated. These variations may be offset largely by the changes in reactive demand if motor loads predominate.

5.7.11 Solenoids

The force of ac solenoids varies approximately as the square of the voltage. In general, solenoids are designed to operate satisfactorily on 10% overvoltage and 15% undervoltage.

5.7.12 Solid-State Equipment

Thyristors, transistors, and other solid-state devices have no thermionic heaters. They are not as sensitive to long-time voltage variations as electron tube components. Internal voltage regulators are provided frequently for sensitive equipment so that it is independent of supply system regulation. Solid-state equipment is, however, generally limited regarding peak voltage because it can be adversely affected by abnormal voltages of even microsecond duration. An individual study of the maximum voltage capability of the equipment, including surge characteristics, is necessary to determine the effect of maximum system voltage or to determine whether abnormally low voltage will result in malfunction.

5.7.13 Control Relays and Magnetic Starters

The force of the magnetic devices varies approximately as the square of the voltage. Standards require successful operation at 10% overvoltage and 15% undervoltage. Although standards do not refer to dropout voltage, these devices will generally hold in down to 65–75% voltage or, sometimes, lower.

5.7.14 Transformers

Undervoltage operation of a transformer has no detrimental effect on the transformer, unless the load current is thereby increased sufficiently to cause an overcurrent condition. Operation of transformers at secondary overvoltage up to approximately 110% at no load or 105% at full load generally causes no harmful effects. (See the IEEE C57 Standards Series for actual limits.) Voltages higher than these can cause saturation of the transformer core, thereby increasing the magnetizing current and the core losses. Continued operation in the overexcited region will increase transformer temperature and may lead to premature failure of the unit.

5.8 Basic Design Considerations

5.8.1 General

Selection of voltage levels for distribution power requires careful consideration of several elements of the system (see Sections 3. and 9. for additional information):

- 1) The total load to be served and how the load will be divided if more than one transformer or bus is involved
- 2) The size load at which the division between medium-voltage and low-voltage service will occur
- 3) Starting current of large motors and bus loading conditions during starting

- 4) Relative costs of power distribution equipment and utilization equipment (particularly switchgear, motors, and cable) with respect to different voltage ratings
- 5) Compatibility with existing and/or future facilities

5.8.2 Medium-Voltage Distribution System

As indicated in Table 5.1, medium-voltage system nominal voltages are 2400-13 800 V. This system distributes power to large individual loads and to transformers supplying low-voltage distribution systems. Depending on the total load to be served, the medium-voltage distribution system may consist of several separate buses and may require multiple unit auxiliaries or station service (startup) transformers. For large systems or systems that include very large individual loads, it may be desirable to have a dual medium-voltage auxiliaries system (13 800 V and 4160 V, for example).

5.8.2.1 Short-Circuit Considerations

As indicated in Section 10., the short-circuit capability of the switching equipment generally increases as the voltage rating increases. The short-circuit capability generally determines the amount of load that can be connected to the bus. Selection of the voltage level depends on the total load and system fault levels. As a result, auxiliary systems with large loads and high fault current levels tend to be higher voltage systems with multiple medium-voltage buses.

5.8.2.2 Voltage Regulation

System voltage regulation and short-circuit capability present conflicting requirements. Fault levels may be reduced by increasing transformer impedance. However, this increases voltage regulation, particularly during starting of large motors. If voltage regulation and short-circuit constraints cannot be satisfied at a particular voltage level, the short-circuit capability of the switchgear can be increased by selecting a higher nominal system voltage. The increased short-circuit capability permits the use of a lower impedance transformer, thus decreasing the voltage regulation.

5.8.2.3 Economic Considerations

The cost of medium-voltage distribution equipment and motors at different nominal voltage levels is an important consideration. Distribution equipment tends to increase in cost as the voltage rating increases. Variation of motor cost with voltage rating depends on motor size. Smaller medium-voltage motors are more costly as the voltage rating increases, while very large motors are more costly at the lower voltage levels.

The cost of cable increases as the voltage rating increases. However, this increase is at least partially offset by a reduction of conductor size due to lower full-load current at higher rated voltages.

It may be difficult on some large systems to satisfy the short circuit and voltage regulation criteria with a single medium-voltage system that is cost effective. A system with a few very large motors and numerous small to medium size motors may be very uneconomical with a single medium-voltage level. If the large motors require a higher nominal voltage for technical reasons, the cost of the many smaller motors may prove to be excessive at the higher voltage. A possible solution is a dual medium-voltage system with the very large motors connected to the higher-voltage bus and the remaining motors connected to the lower-voltage bus. This alternative generally involves more switching equipment, more complicated transformers, and more complex busing arrangements. These factors must be included in the cost comparisons.

5.8.3 Low-Voltage Distribution System

Most design considerations for the medium-voltage system are also applicable to the low-voltage distribution system. The most common low-voltage system in generating stations is a multiple-bus, 480 V, three-phase system (three-wire or four-wire) stepping down to 120/240 V, single-phase, three-wire, or 208Y/120 V, three-phase, four-wire. The 480 V buses distribute power to most motors not connected to the medium-voltage system plus large heaters and, sometimes, 277 V lighting. The 120/240 V or 208Y/120 V buses supply the remaining small loads in the station.

5.8.3.1 Short Circuit Considerations

Available low-voltage distribution equipment has short-circuit capabilities as indicated in Section 10. These short-circuit ratings have little influence on the selection of the voltage level to be used.

5.8.3.2 Voltage Regulation

Increasing impedance to control fault levels on the low-voltage system increases voltage regulation. If there are large motors connected to the low-voltage buses, voltage regulation becomes particularly important during starting of these motors. The problem becomes even more complex on the low-voltage system because cable and busway impedances are much more significant than at the medium-voltage level.

The breakpoint for motor service at low or medium voltage is usually in the range of 200–400 hp, depending mainly on three factors: medium-voltage level, impedance of the low-voltage system, and cost. As the medium-voltage level is increased, the breakpoint horsepower usually increases due to the technical and economic disadvantages of supplying relatively small motors from a higher medium-voltage system. As the breakpoint is raised, the total load on the low-voltage system usually increases because more and larger motors are now supplied from this system. These increases in total load may affect transformer sizes, bus and breaker ratings, quantity of transformers and buses, or all of these.

5.8.3.3 Economic Considerations

The selection of the low-voltage system nominal voltage is not significantly dependent on cost. However, the division of load between the medium and low-voltage distribution system may have a major effect on the economics of the overall service system design. As mentioned, the breakpoint between low and medium voltage usually has a major impact on the low-voltage system configuration. Obviously, more or larger transformers and higher rated switching equipment will increase the cost of the low-voltage system when the low to medium-voltage breakpoint is raised. However, these low-voltage costs must be weighed against two other factors: the cost of the motors and the cost of medium-voltage switching equipment. The voltage rating of a relatively small motor (200–400 hp) can have a dramatic effect on the cost of the motor. Medium-voltage motors of this size can be quite expensive, particularly at the higher medium-voltage levels. This is due in part to the minimum motor frame sizes that manufacturers have assigned for the various voltage levels. A small motor rated for medium-voltage service may, in fact, require a basic frame several sizes larger than actually required for the horsepower rating. This obviously increases the cost of the motor.

The cost of the medium-voltage switching equipment must also be considered when selecting the breakpoint horsepower. The cost of the switching equipment for a given load is usually significantly higher at the medium-voltage levels than at the lower-voltage level. For small loads, special current transformers and/or relays may be required due to the very low current levels involved.

All of these economic factors must be analyzed and evaluated with the technical pros and cons of each alternative.

6. Fault Considerations

6.1 Introduction

Power generating station auxiliary power systems should be designed to provide power to the in-plant electrical loads in a safe and reliable manner. One consideration of vital importance during the design stages is the determination of fault currents. Uncontrolled short circuits can cause outages of vital loads needed for plant operation, resulting in loss of generation capacity by temporary and/or long-term shutdown of generating units. Uncontrolled short circuits can also cause extensive equipment damage, personnel injury or fatality, and fire damage.

In order to control damage and minimize shutdown time, the available fault current must not exceed the ratings of the auxiliary power system equipment, and the fault should be quickly isolated from the auxiliary system. The magnitude of the fault current to be allowed on the system must be established and accommodated in the design during the conceptual design stage. The circuit switching devices must be able to handle the interruption of fault currents and isolate the fault from the unfaulted portions of the system.

The computer has long been recognized by the power system engineer as a useful tool, particularly during the conceptual design stage of an electric generating station for the determination of fault currents, circuit breaker sizing, and load-flow analysis throughout the station auxiliary system. Although the use of the computer for fault calculations is a widespread industry practice, this section will focus on the manual calculation technique in order to provide a thorough understanding of fault considerations.

The purpose of this chapter is to

- 1) Describe probable sources of fault current
- 2) Illustrate the nature and waveshape of fault currents
- 3) Introduce terms needed for an understanding of faults
- 4) Identify equipment ratings related to fault currents
- 5) Illustrate methods of fault calculations
- 6) Provide typical data used in fault calculations
- 7) Show the effect fault currents have on auxiliary power system design
- 8) Serve as a reference source for subjects related to fault considerations that are not covered in detail in this section

6.2 References

[1] ANSI C37.06-1987, American National Standard Preferred Ratings and Related Required Capabilities for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.⁹

[2] ANSI C37.16-1988, American National Standard Preferred Ratings, Related Requirements, and Application Recommendations for Low-Voltage Power Circuit Breakers and AC Power Circuit Protectors.

[3] ANSI C37.46-1981 (Reaf 1987), American National Specifications for Power Fuses and Fuse Disconnecting Switches.

[4] IEEE C37.04-1979 (Reaf 1988), IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (ANSI).¹⁰

[5] IEEE C37.010-1979, IEEE Standard Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (ANSI).

[6] IEEE C37.13-1990, IEEE Standard for Low-Voltage AC Power Circuit Breakers Used in Enclosures (ANSI).

[7] IEEE C37.14-1979, IEEE Standard for Low-Voltage DC Power Circuit Breakers Used in Enclosures (ANSI).

[8] IEEE C37.41-1988, IEEE Standard Design Tests for High-Voltage Fuses, Distribution Enclosed Single-Pole Air Switches, Power Fuses, Fuse Disconnecting Switches, and Accessories (ANSI).

[9] IEEE Std 27-1974 (Withdrawn), IEEE Standard for Switchgear Assemblies Including Metal-Enclosed Bus.

⁹ANSI publications are available from the Sales Department, American National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036, USA.

¹⁰IEEE publications are available from the Institute of Electrical and Electronics Engineers, Service Center, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA.

- [10] IEEE Std 315-1975, IEEE Standard Graphic Symbols for Electrical and Electronic Diagrams (ANSI).
- [11] IPCEA P-54-440-1972, Ampacities in Open-Top Cable Trays.¹¹
- [12] IPCEA S-135-1-1962, Power Cable Ampacities, Copper Conductors.
- [13] IPCEA S-135-2-1962, Power Cable Ampacities, Aluminum Conductors.
- [14] NEMA AB1-1986, Molded Case Circuit Breakers.¹²
- [15] NEMA BU1-1983, Busways.
- [16] “Calculated Symmetrical and Asymmetrical Short-Circuit Current Decrement Rates on Typical Power Systems,” *AIEE Transactions (Power Apparatus and Systems)*, Vol. 75, June 1956, pp. 274–285.
- [17] Huening, W. C., Jr. “Interpretation of New American National Standards for Power Circuit Breaker Application,” *IEEE Transactions on Industry and General Applications*, Vol. IGA-5, Sept./Oct. 1969, pp. 501–523.
- [18] *Transmission and Distribution*, Westinghouse, 1964.

6.3 AC Fault Current — AC Component

When a fault occurs at a point on the auxiliary system, there is an abnormal inrush of current to that point. Primary sources of such current are energy-conversion devices that take the form of rotating machines. The four basic sources of fault current on station service systems are

- 1) Synchronous generators
- 2) Synchronous motors and condensers
- 3) Induction machines
- 4) Transmission system (considered to be a constant voltage and constant impedance generator)

The amount of current at the fault point is determined by the internal electromotive forces of the machines in the network, by their impedances, and by the impedances in the network between the machines and the fault. Therefore, when determining the magnitude of short-circuit currents, all sources of short-circuit current should be included in the analysis, and the impedance characteristics of the sources should be known or reasonably estimated.

This section discusses the various sources of fault current and how the impedance of the sources is used to describe the time-varying current that is produced during a short circuit.

6.3.1 Rotating Machine Reactance

During normal operation of the auxiliary power system, the unit generator delivers alternating current to the network while the auxiliary system loads and the transmission system loads absorb alternating current. Upon the occurrence of a fault on the auxiliary system, the unit generator continues to contribute current to the network. However, the transmission system and the auxiliary system motors behave as sources of current instead of loads and contribute to the fault current as illustrated in Fig 6.1. The exact manner in which the motor stops drawing current and begins to act as a generator of current is relatively unimportant in fault considerations. What is important is

- 1) The fact that the motor does become a generator
- 2) How the current appears at its terminals
- 3) How the generated current can be represented in mathematical terms for use in system design

¹¹IPCEA documents are available from the Insulated Cable Engineers Association P.O. Box 440, South Yarmouth, MA 02664, USA.

¹²NEMA publications are available from the National Electrical Manufacturers Association, 2101 L Street NW, Washington, DC 20037, USA.

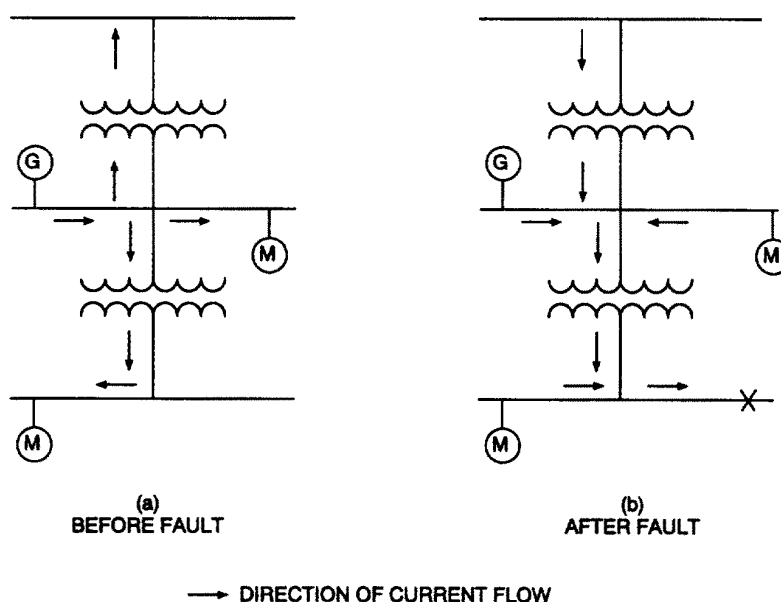


Figure 6.1 — Current Flow Before and After Fault Occurrence

When a three-phase bolted fault (all three phases connected together through a zero impedance conductor) occurs across the terminals of an ac generator with no load, the current in all three phases starts out at a high value and decays to a steady-state value some time after inception of the fault. (A fault current can be represented as a sum of two components: a dc component and an ac component. In this section, only the alternating component of the current is discussed, and is depicted in Fig 6.2. The dc component is discussed more fully in 6.4.) The currents in each of the three phases are identical, but are displaced by 120° .

The wave, whose envelope is shown in Fig 6.2, may be divided into the following three periods:

- 1) The *subtransient period*, which lasts only for the first few cycles, during which the current decrement (envelope OA in Fig 6.2) is very rapid. The rms value of this current is called the “initial symmetrical rms current” (subtransient current) because it is the rms value of the ac component of current immediately after the fault occurs.

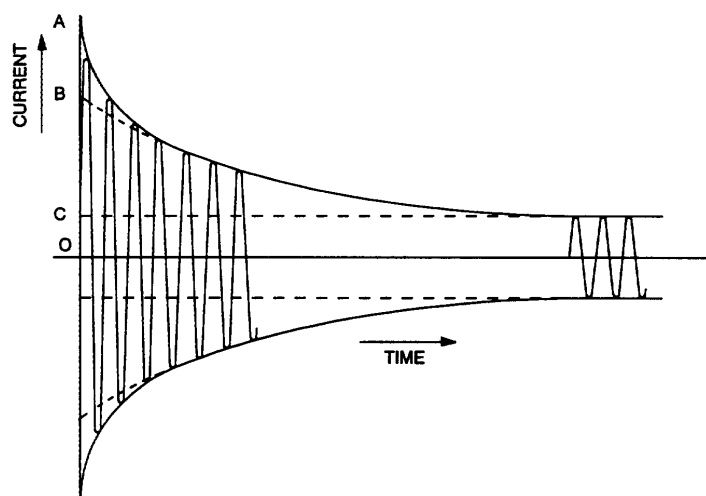


Figure 6.2 — Current as a Function of Time for a Generator Short-Circuited While Running at No Load (The transient dc component has been eliminated.)

- 2) The *transient period*, which covers a relatively longer time, during which the current decrement (envelope OB in Fig 6.2) is more moderate. The rms value of this current is called the “transient current.”
- 3) The *steady-state period* is the time period in which a sustained (constant value) short-circuit current exists. The maximum value of the sustained short-circuit current is shown as distance OC in Fig 6.2.

To model these three periods of time-varying current, the EMF of the machine is assumed to remain constant with time (i.e., machine initially unloaded), and the reactance of the machine is assumed to change during the fault. The three reactances are given the name and symbols of

- 1) *Subtransient reactance*, X_d'' . Determines the current during the first few cycles of a fault that has a duration of approximately 0–6 c. The manufacturer will typically provide both saturated and unsaturated values of subtransient reactance. The saturated value should be used in short-circuit calculations.
- 2) *Transient reactance*, X_d' . Determines the machine current following during fault conditions following the period when subtransient reactance is the controlling value and before steady-state conditions are reached. The transient current has a duration in the range of 6–25 c. Again, the manufacturer will typically provide both saturated and unsaturated values of transient reactance. The saturated (rated voltage) value should be used in short-circuit calculations.
- 3) *Synchronous reactance*, X_d . Determines steady-state current flow that has a duration of 25 c to infinity.

Note that the time periods during which each reactance is applicable depend upon the design of the machine. Also, the reactance models are discrete approximations for a continuously changing reactance.

The rotating machine reactances normally provided by the manufacturer assume no load at the machine terminals, unless specifically requested otherwise. Having a load connected to the alternator and having external impedance in the fault path causes the current waveform to be altered from the waveform for a no-load condition. Particularly, the rate of decrement is not so great (see [5] and [16]¹³). An approximate method of calculating fault current for a loaded generator is presented in the Appendix of this section, which assumes all voltage sources are in phase, the generator is unloaded, and impedances are linear.

6.3.2 Generator Contribution

The qualitative waveform of the current delivered by a synchronous generator to fault is shown in Fig 6.3(a).

¹³The numbers in brackets correspond to those of the references in 6.2.

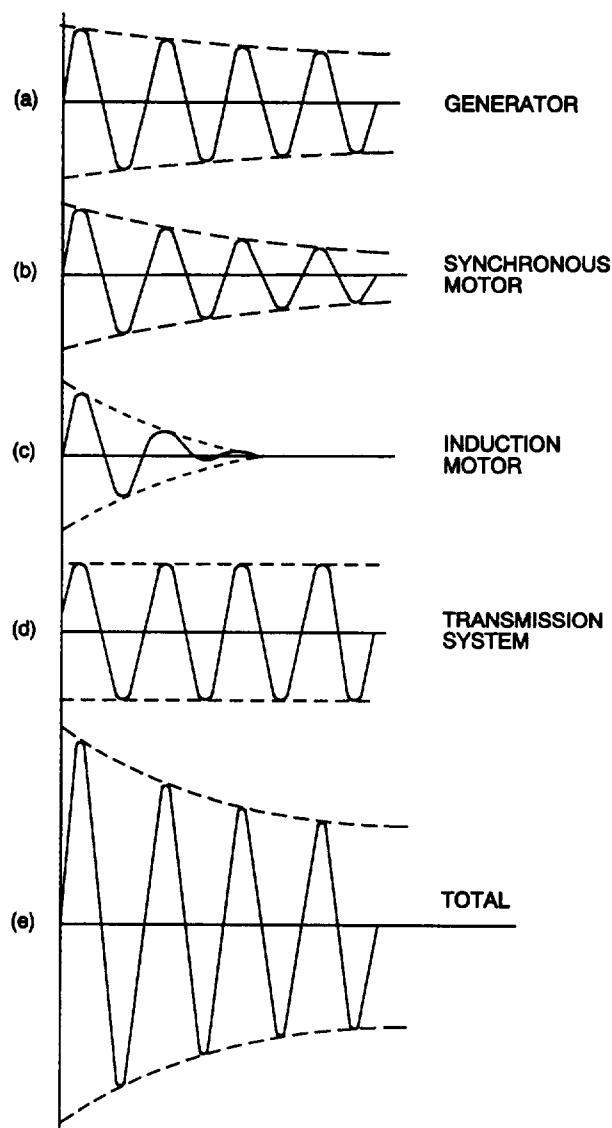


Figure 6.3 — Typical Waveshapes of Symmetrical Short-Circuit Current From Generators, Synchronous Motors, Induction Motors, and the Transmission System

A generator continues to supply current to a fault as long as field excitation is present and the prime mover continues to drive the generator. This results in the short-circuit current decaying to a constant nonzero steady-state value.

When making a short-circuit calculation, the most accurate reactance data available should always be used. But, in the conceptual design stages of a new plant, calculations frequently must be made without such specific data being available, and approximate data must therefore be used. Table 6.1 includes a list of typical reactance values in per-unit for generators (see 6.8.5 for definitions of per-unit values).

6.3.3 Synchronous Motor Contribution

Due to the similarity in the construction of synchronous motors and synchronous generators, they can be expected to act in a similar manner during a faulted condition. During a fault, inertia of the load and the motor rotor drives the synchronous motor just as the prime mover drives a generator. The difference is that, during a fault, the synchronous

motor is driven by stored mechanical energy and, therefore, slows down and stops quickly relative to a continuously driven generator.

**Table 6.1 —
Typical Reactance Values for Induction and Synchronous Machines (Per Unit of Machine kVA
Ratings* on Machine kV Base)**

	X''_d	X'_d
Turbine generators [†]	0.09	0.15
2 poles	0.15	0.23
4 poles		
Salient-pole generators with Damper windings [†]		
12 poles or less	0.16	0.33
14 poles or more	0.21	0.33
Synchronous motors	0.15	0.23
6 poles	0.20	0.30
8-14 poles		
16 poles or more	0.28	0.40
Synchronous condenser [†]	0.24	0.37
Synchronous converters [†]	0.20	—
600 V dc	0.33	—
250 V dc		
Individual induction motors, usually above 600 V	0.17	—
Groups of motors, each less than 50 hp, usually 600 V and below [‡]	0.25	—

NOTE — Approximate synchronous motor kVA can be found from motor horsepower ratings as follows:

$$\begin{aligned} 0.8 \text{ power factor motor - kVA base} &= \text{hp rating} \\ 1.0 \text{ power factor motor - kVA base} &= 0.8 \text{ hp rating} \end{aligned}$$

*Use manufacturer's specified values if available.

[†] X'_d is not normally used in short-circuit calculations.

[‡]The value of X''_d for groups of motors has been increased slightly to compensate for the very rapid short-circuit current decrement in these small motors. A lower value of X''_d will normally be appropriate for groups of large motors.

Fig 6.3(b) shows the qualitative waveform of the current delivered to a fault by a synchronous motor. Note that its decay is faster than that of the generator, primarily due to the difference in prime movers.

Typical reactance values for synchronous motors are given in Table 6.1.

6.3.4 Induction Motor Contribution

The inertia of the load and rotor of an induction motor drives the motor after a short circuit in the same manner as described earlier for the synchronous motors. However, the excitation of the field windings of an induction motor is self-induced, and thus results in a much faster decay of fault current than is the case for a synchronous motor. Fig 6.3(c) can be compared with Fig 6.3(b) as an illustration of this. Table 6.1 shows the reactance values for induction motors. No value for the transient reactance is given because of the fast decay of current. For this reason, only the subtransient current of an induction motor is usually considered in fault calculations.

6.3.5 Transmission System Contribution

The transmission system usually represents a large source of power and provides a relatively constant short-circuit current during a fault, as shown in Fig 6.3(d). Consequently, it can be modeled as a constant equivalent impedance. This value of impedance can generally be calculated from the maximum value of system available short-circuit kilovolt-amperes. Or, it can be determined by the utility by means of a short-circuit study.

6.3.6 Other Sources

Other sources of fault current that may be attached to the auxiliary power system are synchronous condensers and synchronous converters. Both of these are treated like synchronous motors, and their reactance values are given in Table 6.1.

Also, in that portion of the power system operating at 600 V or less, there are generally numerous small motors. It is usually impractical to represent each small motor in the impedance diagram. Therefore, they are often grouped together and represented by a single reactance as given in Table 6.1 (i.e., twenty 5-hp motors may be represented as one 100 hp motor with a reactance of 0.25 pu).

6.3.7 Total AC Waveform

The total symmetrical short-circuit waveform is made up of the sum of all the current sources contributing to the fault, as shown in Fig 6.3(e). It is this current magnitude, along with the dc component that accompanies it, that must be considered for short-circuit protective device application.

Represented mathematically, the rms value of the ac component of a synchronous generator is

$$i_{ac} = (i_d'' - i_d')e^{-\frac{t}{T_d''}} + (i_d' - i_d)e^{-\frac{t}{T_d'}} + i_d$$

where

$$i_d'' = \frac{|Ei''|}{X_d''} \quad = \text{subtransient component of current}$$

$$i_d' = \frac{|Ei'|}{X_d'} \quad = \text{transient component of current}$$

$$i_d = \frac{|Ei|}{X_d} \quad = \text{steady-state component of current}$$

$$T_d'' = \frac{X_d''}{X_d'} T_{do}'' \quad = \text{short-circuit subtransient time constant}$$

$$T_{do}'' \quad = \text{subtransient open-circuit time constant, normally given by the manufacturer}$$

$$T_d' = \frac{X_d'}{X_d} T_{do}' \quad = \text{short-circuit transient time constant}$$

$$T_{do}' \quad = \text{transient open-circuit time constant, normally given by the manufacturer}$$

E_i'' , E_i' , and E_i are the internal prefault machine voltage (in pu) behind the subtransient reactance, transient reactance, and the synchronous reactance, respectively. For an unloaded generator, $E_i'' = E_i' = E_i$. For a loaded generator, the internal machine voltages (E_i'' , E_i' , and E_i) are not equal and are a function of the machine loading.

A sample calculation using this formula is presented in A1.1.

6.4 AC Fault Current – DC Component

In 6.3, only the symmetrical ac component of the short-circuit current was discussed. There is also a dc component present in at least two phases during a fault, depending on the time at which the fault occurred. The total fault current is the sum of the ac and dc components.

6.4.1 Symmetry and Asymmetry

When describing the total fault-current waveform, the terms symmetry and asymmetry are often used. A symmetrical wave is one in which the envelope of the peaks of the waves are symmetrical about the zero axis. An asymmetrical wave is one in which the peaks of the waves are not symmetrical about the zero axis. All of the currents in Fig 6.3 are symmetrical. When the dc component of fault current is added to the symmetrical component of fault current, asymmetry results, and a current envelope in the form shown in Fig 6.4 is produced.

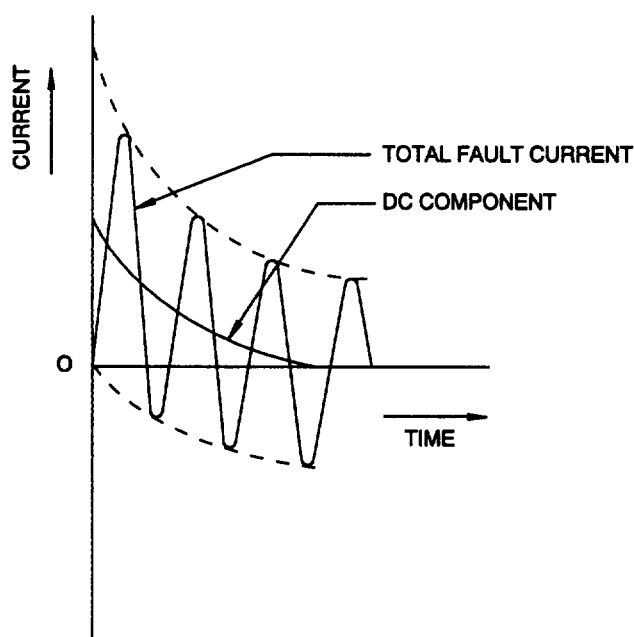


Figure 6.4 – Typical Waveshape of Asymmetrical Short-Circuit Current (From all sources illustrated in Fig 6.3 plus dc component.)

6.4.2 Inductive Circuit Characteristics

In a medium-voltage auxiliary power system, the impedance is generally assumed to be purely inductive due to the small amount of resistance compared to the reactance in the circuit (see IEEE C37.010-1979 [5]). A constant voltage source with no decay or time-varying source reactance, with no initial load, and with a three-phase bolted fault suddenly applied is assumed. In such an oversimplified case (see B2¹⁴), the circuit that is modeled is a purely inductive

¹⁴The numbers in brackets, when preceded by the letter “B,” correspond to the Bibliography in 6.11

circuit with the current lagging the voltage by 90° , as in Fig 6.5(a). Another condition that the current adheres to is that it must start from zero at a fault location since the current can't change instantaneously at that point. Using these two restraints, current lags voltage by 90° and current can't change instantaneously, a development of how the dc component comes about can be made.

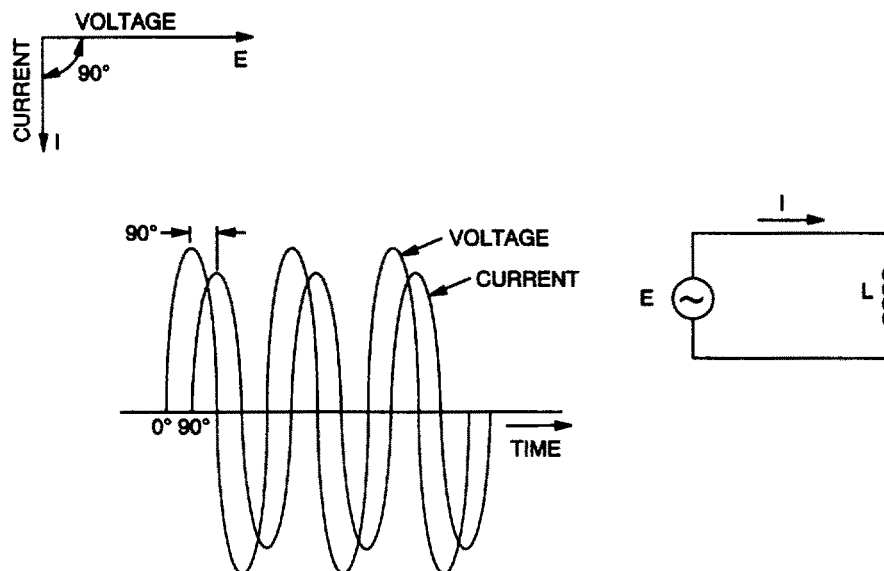


Figure 6.5(a) —Diagrams Illustrating the Phase Relations of Voltage and Current

When a short circuit occurs in a purely reactive circuit, the short-circuit current starts at zero, but its magnitude varies dependent upon the point on the voltage wave at which the short-circuit occurs. The two extremes are

- 1) *Short circuit occurs at the peak of the voltage wave.* In this case, the current sine wave has maximum initial slope and is therefore symmetric about the zero axis, as shown in Fig 6.5(b). This form of short-circuit current is called a symmetrical short-circuit current.
- 2) *Short circuit occurs at the zero value of the voltage wave.* The shortcircuit current has the same waveform as the voltage, lags it by 90° , has zero initial slope, and therefore is displaced from the zero axis, as shown in Fig 6.5(c). This form of short-circuit current is called a fully asymmetrical short-circuit current.

Asymmetrical short-circuit currents are divided into simple components when applying protective devices. These simple components are a symmetrical ac current and a dc current that exist simultaneously. When the instantaneous values of these two components are added together at any point in time, the resultant is the asymmetrical short-circuit current. This procedure makes it easier to calculate the magnitude of the short-circuit current at any time after the short circuit occurs.

Fig 6.5(d) shows an asymmetrical short-circuit current resolved into its ac and dc components. Note that the symmetrical ac component is generated by rotating machines, and the dc component is a result of the relationship between current and voltage in an inductive circuit.

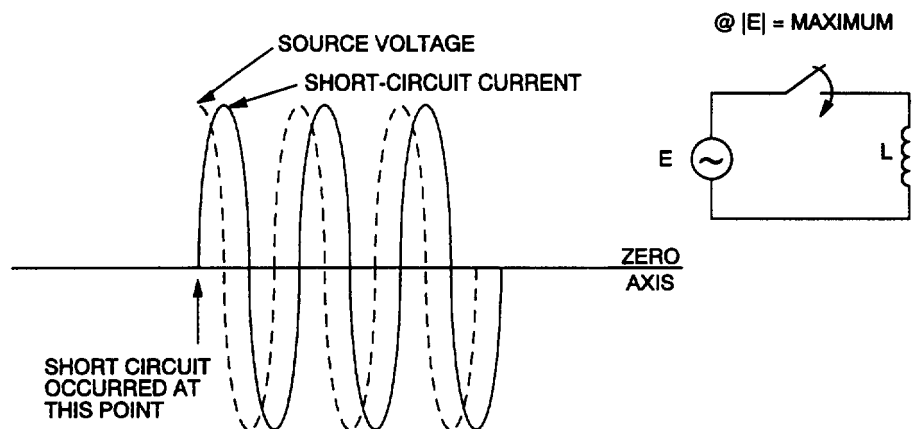


Figure 6.5(b) – Symmetrical Short-Circuit Current and Source Voltage for Zero-Power-Factor Circuit

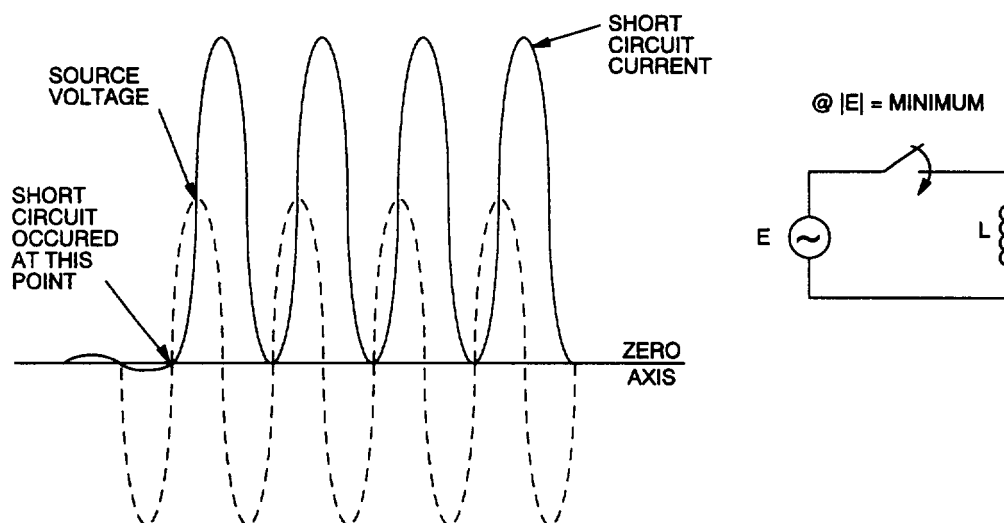


Figure 6.5(c) – Asymmetrical Short-Circuit Current and Source Voltage in Zero-Power-Factor Circuit

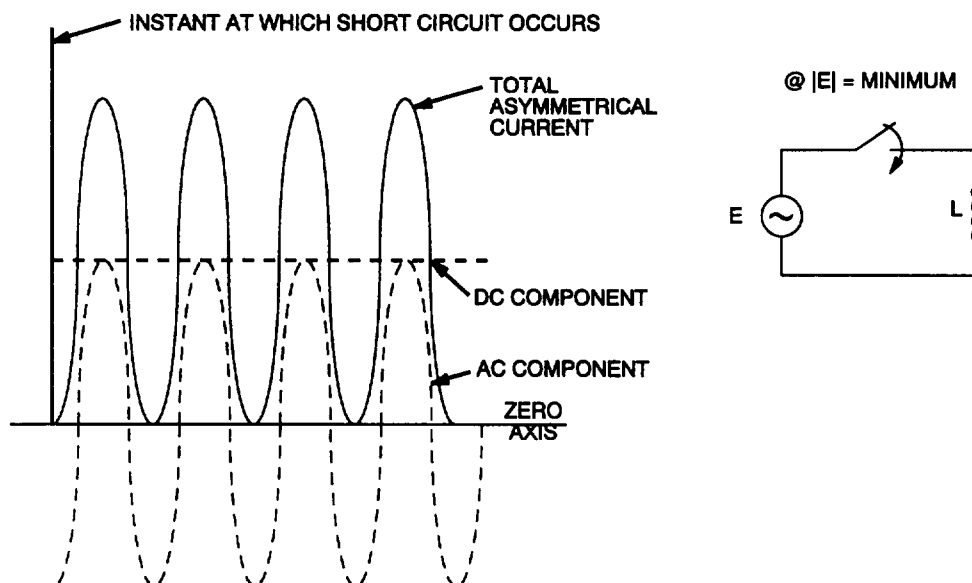


Figure 6.5(d) — Short-Circuit Current Wave Illustrating Components of Asymmetrical Current (In practical circuits, dc component would decay to zero in a few cycles.)

6.4.3 Initial Magnitude

The magnitude of the dc component of a shortcircuit current will depend upon the point on the voltage wave at which the fault occurs. If the fault occurs at a voltage maximum or minimum, the current wave will be a symmetrical sinusoidal wave having a zero dc component. If the fault occurs at a voltage zero, the current wave will be a completely offset wave, and the dc component will be equal to the peak value of the ac symmetrical component, as shown in Fig 6.5(d). If the fault is applied anywhere between these two extremes, the initial value of the dc component will be equal to the ac component at the instant of fault, but opposite in sign. Hence, the condition that a zero value of total initial fault current must exist is satisfied, as is shown in Fig 6.5(e).

6.4.4 Effect of Resistance

In systems containing both reactance and resistance, the point on the voltage wave at which the fault occurs to produce the maximum offset depends on the reactance/resistance ratio at the point of the fault. Maximum asymmetry is obtained when the short circuit occurs at a time angle equal to θ° , measured forward from a voltage peak where tangent θ equals the reactance-to-resistance ratio. The short-circuit current will be symmetrical when the fault occurs at θ° , measured forward from a voltage zero. Fig 6.5(f) shows maximum asymmetry with an X/R ratio equal to 1.

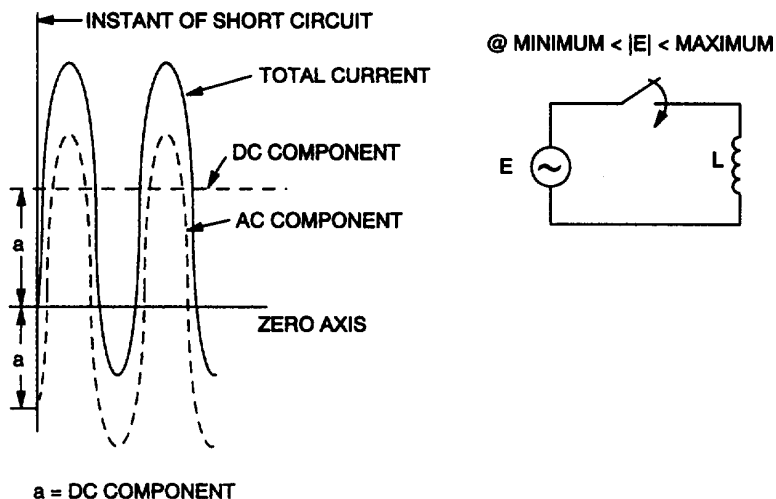


Figure 6.5(e) — Components of Asymmetrical Short-Circuit Current in Which Short Circuit Occurred at Some Point Between the Zero Point and the Peak of the Source Voltage Wave. (This is a theoretical condition similar to that shown in Fig 5(d).)

Since no dc sources exist in the system, the dc component of the fault current is derived from the ac system due to the disturbances caused by the fault. Hence, the dc component will decay as it dissipates itself as I^2R losses by flowing from the system through the system resistance. The time required for the dc component to decay to zero is dependent upon the system X/R ratio.

The decaying of the dc component is modeled in Fig 6.5(g) by an exponentially decaying function that starts out at its maximum value and decays to zero with the time constant ($X/2\pi fR$ in seconds or $X/2\pi R$ in cycles) of the system. The larger the resistance is in proportion to the reactance, the sooner the direct current is dissipated.

The combination of the dc component and the symmetrical ac component gives an asymmetrical wave that changes to a symmetrical wave when the dc component has disappeared.

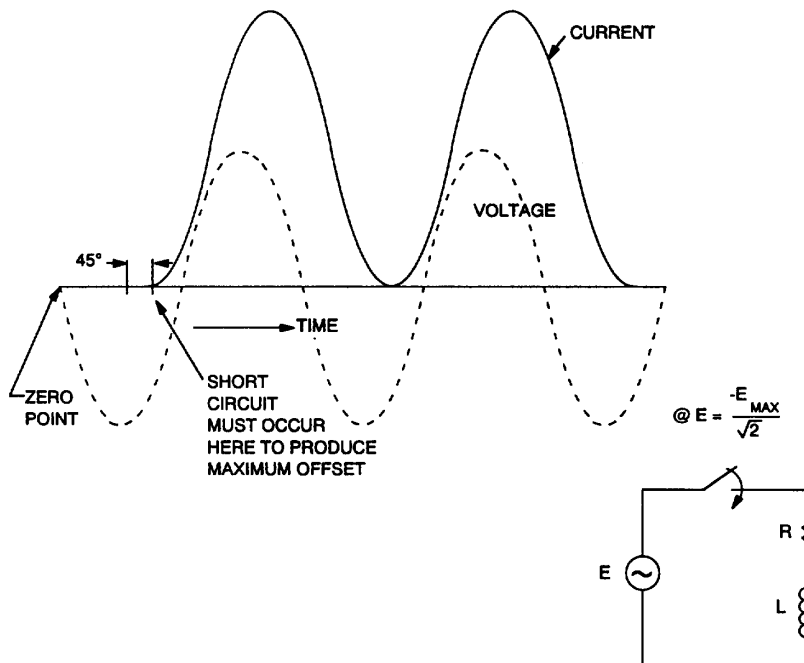


Figure 6.5(f) — Short-Circuit Current and Source Voltage in Circuit With Equal Reactance and Resistance (This condition is theoretical and is shown for illustration purposes only. The short-circuit current will gradually become symmetrical in practical circuits.)

Fig 6.5(g) assumes no decrement in the symmetrical ac component. A more representative curve of a fault current is shown in Fig 6.5(h). The three important features to note about this fault current waveform that are essential for understanding fault current calculation procedures are

- 1) A large initial offset of the current due to the transient dc component
- 2) The exponentially decaying dc component with a time constant of $X/2\pi/R$ of the circuit
- 3) The decaying of the symmetrical ac component with time due to time-varying machine reactance and the impedance between the location of the fault and the source of generation

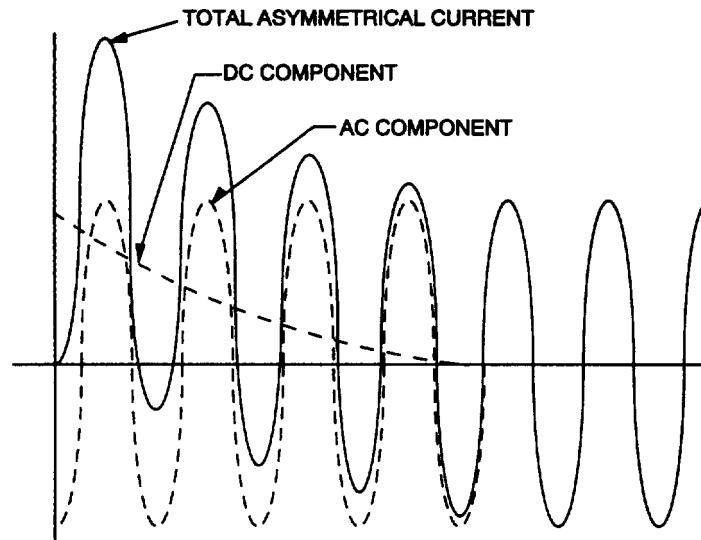


Figure 6.5(g) – Waveshape of Short-Circuit Showing Decay of DC Component and how Asymmetrical Short-Circuit Gradually Becomes Symmetrical When DC Component Disappears

6.4.5 DC Offset

The maximum initial value of the dc component would flow if the short circuit occurs when ac voltage is at a zero minimum in one of the phases (when R is negligible). The maximum initial value in that phase would be

$$\begin{aligned}
 I_{\text{dcmax}} &= \sqrt{2}I_{\text{acmax}}(\text{rms}) \\
 &= \sqrt{2}\frac{E}{X_d}
 \end{aligned}$$

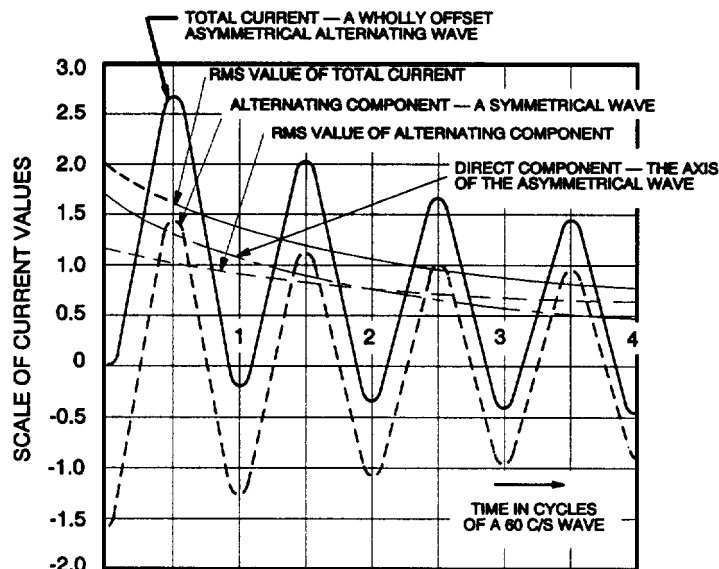


Figure 6.5(h) — Structure of Asymmetrical Short-Circuit Current Wave

where

E is the maximum steady-state pre-fault voltage at the fault location in pu (and should be set at 1.05 pu for a fault at the generator terminals due to generator regulator action) to obtain the maximum fault current value.

As a function of time, the dc component of current due to a short circuit on a synchronous generator is given by

$$i_{dc_{gen}} = \frac{\sqrt{2}Ei''}{X_d} e^{-\frac{t}{T_{a3}}}$$

$$T_{a3} = \frac{X_2}{2\pi f R_a} = \text{armature short-circuit time constant}$$

X_2 = generator negative sequence reactance

R_a = dc resistance (or effective resistance) of the armature circuit

f = system frequency

For the case where the dc contribution from the system is desired, it is given by

$$i_{dc_{system}} = i_{dc_{max}} e^{-\frac{t}{T_{system}}}$$

where

$$T_{system} = \frac{X}{2\pi f R} \text{ (seconds)}$$

$$= \frac{X}{2\pi R} \text{ (cycles)}$$

R = system resistance

X = system reactance

This equation indicates the significance of time and the X/R ratio in determining i_{dc} . Sample calculations using these formulas are presented in A1.1.

6.5 RMS Value of Total Asymmetrical Current

The approximate value of the total rms current (the asymmetrical current), as a function of time, is computed by the formula

$$i_{\text{total}} = \sqrt{i_{\text{ac}}^2 + i_{\text{dc}}^2}$$

In 6.3 and 6.4, the formulas for the ac and dc current components were presented. A sample calculation using this formula is presented in A1.1.

6.5.1 Multiplying Factors

The rms value of symmetrical and asymmetrical fault current, at any time during a fault, can be calculated nearly precisely. However, in order to obtain this degree of precision, extremely complicated techniques must be employed to determine the actual decrement of the dc component and the apparent reactance of the sources at any point in time. The nearly precise method may be used, but it is quite time consuming without the aid of a computer. Furthermore, it is generally not necessary to be quite so precise during initial design stages. Techniques have evolved in which the dc component, symmetrical ac component, or total asymmetrical current can be accounted for by a simple multiplying factor applied to a simplified symmetrical E/X calculation. These multipliers consider such variables as: time when current value is needed, X/R ratio of the circuit, and location in the circuit where the fault occurs. A further discussion of this subject is given in 6.8.

6.6 Fault Types and Magnitudes

Even in the best designed auxiliary systems, the possibility of a fault occurring does exist. To design for fault protection, a knowledge of the type of fault that can occur at the point in question, as well as its magnitude, must be considered. It is the purpose of this section to compare fault types and decide which gives the “worst-case” condition to be used in a fault study.

6.6.1 Types of Faults

A three-phase power system may be subjected to the following types of faults:

- 1) Three-phase
- 2) Phase-to-phase
- 3) Phase-to-phase-to-ground
- 4) Phase-to-ground

All four of these are illustrated in Fig 6.6 with an unloaded generator. Note that these four types of faults could also have resistance in the fault path, but that would serve to decrease the magnitude of the fault current.

6.6.2 Magnitudes From Symmetrical Component Theory

In terms of symmetrical components (see [B5]), the magnitude of the four different types of faults on the terminals of a symmetrical Y-connected synchronous generator, operated at no load with balanced generated voltages, are

- 1) Three-phase fault
 $I_f = E_a / Z_1$

- 2) Phase-to-phase fault

$$I_f = \sqrt{3}E_a / (Z_1 + Z_2)$$

- 3) Phase-to-phase-to-ground fault

$$I_b = -j\sqrt{3}E_a \frac{Z_0 + 3Z_n - aZ_2}{Z_1Z_2 + (Z_1 + Z_2)(Z_0 + 3Z_n)}$$

$$I_c = +j\sqrt{3}E_a \frac{Z_0 + 3Z_n - a^2Z_2}{Z_1Z_2 + (Z_1 + Z_2)(Z_0 + 3Z_n)}$$

$$I_n = \frac{-3E_aZ_2}{Z_1Z_2 + (Z_1 + Z_2)(Z_0 + 3Z_n)}$$

where

$$a = -1/2 + j\sqrt{3}/2$$

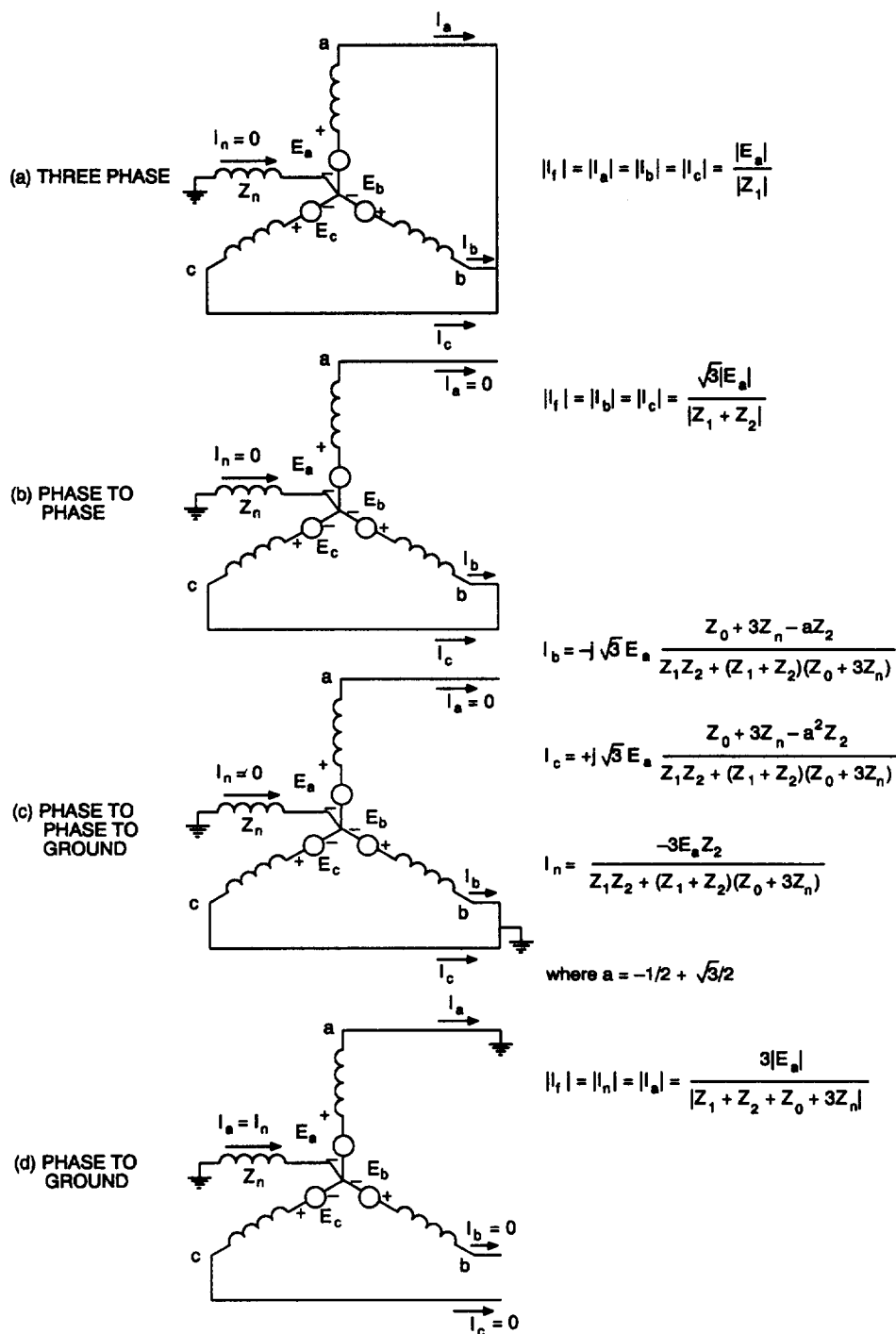


Figure 6.6 — Types of Faults on a Three Phase System

- 4) Phase-to-ground fault

$$I_f = 3E_a / (Z_1 + Z_2 + Z_0 + 3Z_n)$$

where

- E_a = pre-fault line-to-neutral generator voltage
- Z_1 = positive-sequence impedance
- Z_2 = negative-sequence impedance

$$\begin{aligned} Z_0 &= \text{zero-sequence impedance} \\ Z_n &= \text{impedance of neutral grounding device} \end{aligned}$$

Assuming that the positive-sequence impedance equals the negative-sequence impedance (while not correct for rotating machines, this approximation will usually lead to a satisfactory answer when the impedances involved have transformer and lines in series with the rotating machines), the phase-to-phase fault magnitude is 86.6% of a three-phase fault magnitude.

Using the same assumptions along with a solidly grounded system ($Z_n = 0$), the phase-to-ground fault current reduces to

$$I_f = \frac{Ea}{Z_1} \frac{3}{(Z_0/Z_1 + 2)}$$

This equation shows that some concern must be given to phase-to-ground faults on solidly grounded systems because their magnitude may exceed a three-phase bolted fault. Often, impedance (usually resistance) grounding is used, and the line-to-ground fault current is much less than a three-phase fault current. Also, in practical plant circuits, the Z_0/Z_1 ratio is normally greater than one and reduces the auxiliary phase-to-ground fault current below the three-phase fault value (see [B8] and [B9]).

Therefore, a three-phase fault condition will determine the worst-case fault current to be expected on the system, except in the special case of a phase-to-ground fault in which there is solid grounding or low-resistance grounding that can cause the Z_0/Z_1 ratio to be less than one (see IEEE C37.010-1979 [5] for a case in which the phase-to-ground fault current is larger than the three-phase fault current).

6.7 Protective Devices and Equipment Short-Circuit Ratings

One of the main purposes of a fault calculation is to determine fault current magnitudes for the proper application of overcurrent protective devices to insure that the thermal withstand capability of any piece of equipment is not exceeded. Depending on the device for which the short-circuit current is being calculated, the fault calculation assumptions and procedures vary greatly. To assist in the understanding of why certain assumptions are made in the calculations, an understanding of the device operation is essential.

The background of equipment and protective device ratings, as well as the basic characteristics of short-circuit currents, must be understood in order to select the appropriate rotating-machine reactance and multiplying factors to use in calculating the proper short-circuit current magnitudes.

The rating structure of a device is an aid in predicting how the device will perform under conditions in which current varies with time. The purpose of this section is to discuss these rating structures and the operation of protective devices in relation to fault considerations.

6.7.1 Circuit Breakers

Auxiliary power systems are divided into two classes according to voltage levels: medium voltage (1001 V to 15 000 V) and low voltage (1000 V and below).

The fundamental operating principles of all power circuit breakers applied to the medium-voltage system are essentially the same. The time required for the power circuit breaker to interrupt the fault current is composed of the individual component times required for

- 1) The protective relay to sense the fault current and close its contacts
- 2) The circuit breaker operating mechanism to be released
- 3) The circuit breaker contacts to part
- 4) The interruption of the fault current arc within the circuit breaker

The greatest mechanical stresses are sustained by the circuit breaker when maximum current is flowing. Maximum fault current occurs during the first half-cycle after the fault occurs because the dc components of the fault current is greatest at this time, and also because the motors are acting as generators and contributing current to the fault at this time. Thus, the short-circuit stresses on the circuit breakers and other circuit components are at a maximum during the first loop of short-circuit current.

Due to the lack of a dc source and the change in motor reactance, the total fault current decreases in magnitude with an increase in time because the dc component and the motor contribution decreases with time. Hence, the magnitude of current that the circuit breaker is called upon to interrupt is usually slightly to significantly less than the maximum value of fault current available during the first half-cycle following the fault.

Since the fault current is noticeably different $1/2$ c and 3-5 c following the fault, the momentary and interrupting rating of medium-voltage circuit breakers are different. The momentary ($1/2$ c) fault current dictates the required circuit breaker rating for closing and latching. The interrupting (3-5 c) fault current dictates the required circuit breaker rating for interrupting the flow of fault current.

It is these two ratings, closing and latching capability and symmetrical interrupting capability, that must be checked against calculated fault currents before application of a medium-voltage power circuit breaker. References [1], [4], [5], and [17] give the rating structure of the circuit breakers, the capabilities defined by these ratings, and the method of calculating fault currents to use when selecting medium-voltage ac circuit breakers.

The operating mechanism of low-voltage circuit breakers is different from that of medium-voltage circuit breakers. Low-voltage circuit breakers are designed to operate instantaneously at currents near their interrupting rating, thus opening their contacts during the first cycle of the fault and withstanding the resultant mechanical stresses. For the application of low-voltage air circuit breakers, only the first half-cycle current value needs to be calculated. This value is then to be compared to the short time rating of the breaker to determine its adequacy. References [2], [6], and [14] give the rating structure of the circuit breakers, the capabilities defined by these ratings, and a method of calculating fault currents for application of low-voltage ac circuit breakers.

6.7.2 Fuses

Fuses of all types depend on the heat created by the passage of the fault current through them to melt their fusible elements. Since the heat is due solely to the I^2R loss, dc as well as ac components of current will affect them. So, the initial asymmetrical subtransient current will affect fuse operation. However, the effect of the dc offset current decreases in importance very rapidly as the expected fuse melting time increases.

All fuse-interrupting ratings are based on the maximum rms current that can possibly flow in the first cycle after the short circuit occurs. This is the current that would flow if the fuse did not open the circuit before the peak of the first current half-cycle following the fault. Therefore, fuses are rated in terms of available short-circuit current. References [3] and [8] give the rating structure of fuses, the capabilities defined by these ratings, and a method of calculating fault currents for their application.

6.7.3 Relays

The basic data and procedure required for making short-circuit calculations for a relay study are the same as for a circuit breaker duty study. In fault calculations for selecting relay settings, the problem is to determine the minimum values of fault current magnitude expected at certain times following the instant of short circuit, and compare these to the values of current that will be sure to operate the relay at that time. Fault current magnitudes are needed to check the sensitivity and selectivity of the relays, and fault current magnitudes at different times are needed for coordination of the relays.

All overcurrent protective relays can be classified under one of the following headings:

- 1) Instantaneous

- 2) High-speed
- 3) Time-delay
- 4) A combination instantaneous or high-speed and time-delay

Instantaneous relays are responsive to dc, to a certain extent, as well as ac and are fast enough to operate on the first half-cycle of fault current. Therefore, their operating current will be the initial (instantaneous) asymmetrical fault current contributed by all rotating equipment calculated on the basis of its subtransient reactance.

High-speed relays operate in 3 c or less, so the initial asymmetrical fault current is also to be used as their operating current. Actually, the fault current magnitude will drop during the 3 c because of decrement, but the influence of this reduction can generally be neglected in relay studies.

Time-delay relays are too slow to be appreciably affected by the subtransient reactance values of fault current. Therefore, their operating current should be checked against the symmetrical transient reactance current or the steady-state current, depending on the time the relay is to be tripped.

Consequently, the short-circuit information necessary for relay sensitivity and coordination includes (refer to Section 7.):

- 1) Maximum and minimum 0-3 c (momentary) total rms short-circuit current
- 2) Maximum and minimum 3-60 c interrupting duty total rms short-circuit current

6.7.4 Other Equipment

Values of short-circuit current are not only important from the standpoint of protective device application, but also from the standpoint of thermal and mechanical stress on equipment. All passive elements (i.e., cables, busways, and buses) are assigned a mechanical withstand rating based on a momentary asymmetrical short-circuit current. A thermal (I^2t) rating will also be given. These values should be checked before application of equipment to ensure operation without damage or failure to the element. References [9], [11], [12], [13], and [15] contain ratings of various equipment.

6.8 Fault Calculation Tools

This section discusses some basic considerations that should be made in any type of fault calculation. It also lays the groundwork that is to be followed when performing a calculation, with deviations being considered for specific types of applications in the following section. A thorough understanding of these fundamentals is essential before proceeding to specific cases.

6.8.1 Single-Line Diagram

A single-line diagram is a representation of the electrical system by means of single lines and graphic symbols that show sources of short-circuit current (i.e., transmission system ties, generators, synchronous motors, induction motors, synchronous condensers, rotary converters, etc.), and all significant electrical system components, such as transformers, cables, circuit breakers, etc. Representative symbols of electrical devices are listed in IEEE Std 315-1975 [10]. The single-line diagram should be representative of the circuit for which the short-circuit calculation is to be made. Fig 6.7(a) shows a simple single-line diagram.

6.8.2 Selection of Fault Location

When determining the fault duty that a piece of equipment or a protective device is to handle, a fault location should be selected that will result in the maximum short-circuit current that will flow through the device. Generally, this would be a point within the equipment (such as a spare breaker in a switchgear) or in the circuit downstream from the piece of equipment that adds the minimum amount of impedance to the fault circuit. Therefore, only one fault point

need be considered for determining the required duty of a given piece of equipment. However, more than one fault point may need to be checked if the worst-case fault location is not obvious.

6.8.3 Type of Fault

In 6.6, it was shown that a greater short-circuit current could flow, under certain conditions, during a single line-to-ground fault than during a three-phase bolted fault. However, because (1) calculations are more simple, (2) breakers have a higher rating for line-to-ground faults, and, most importantly, (3) line-to-ground fault currents rarely exceed three-phase bolted fault current, a three-phase bolted fault is generally assumed for fault calculations.

6.8.4 Impedance Diagram

An impedance diagram is derived from the single-line diagram by modeling the elements of the single-line diagram that are involved during the short circuit by their representative impedance. The representative impedance reflects the effect of the element on the short-circuit current and depends on many factors. The impedances and magnitude of impedances to be considered for various types of fault-calculation studies depend on many factors, some of which were discussed in 6.3.1 on rotating machine reactance and 6.7 on protective devices. Tables 6.1 through 6.3 and Fig 6.8 can be used to find typical values of circuit element impedances when exact values are unknown.

Once the location of the assumed fault has been decided, an impedance diagram is constructed, as shown in Fig 6.7(b). All fault current sources are connected to a neutral bus. From this diagram, a Thevenin equivalent impedance is calculated at the fault point.

6.8.5 Per-Unit System

In multilevel voltage systems, the easiest way to handle electrical parameters is in the per-unit system. Per-unit is a ratio that expresses one number in terms of another base number:

$$\text{Per Unit} = \frac{\text{A Number}}{\text{Base Number}}$$

The base number is also called a unit value since, in the per-unit system, it has a per unit value of 1, or unity.

In the per-unit system, there are four base quantities: base kilovolt-amperes, base kilovolts, base ohms, and base amperes. When any two of the four are assigned values, the other two values can be derived. It is common practice to assign study base values to kilovolt-amperes and voltage. Base kilovolt-amperes are used throughout the voltage levels, whereas the "nominal" line-to-line system kilovolts are normally used as the base voltage. A summary of frequently used per-unit relationships on a three-phase system are as follows:

Select as bases:

- 1) Base kV as nominal line-to-line voltage
- 2) Base kVA as three-phase kVA

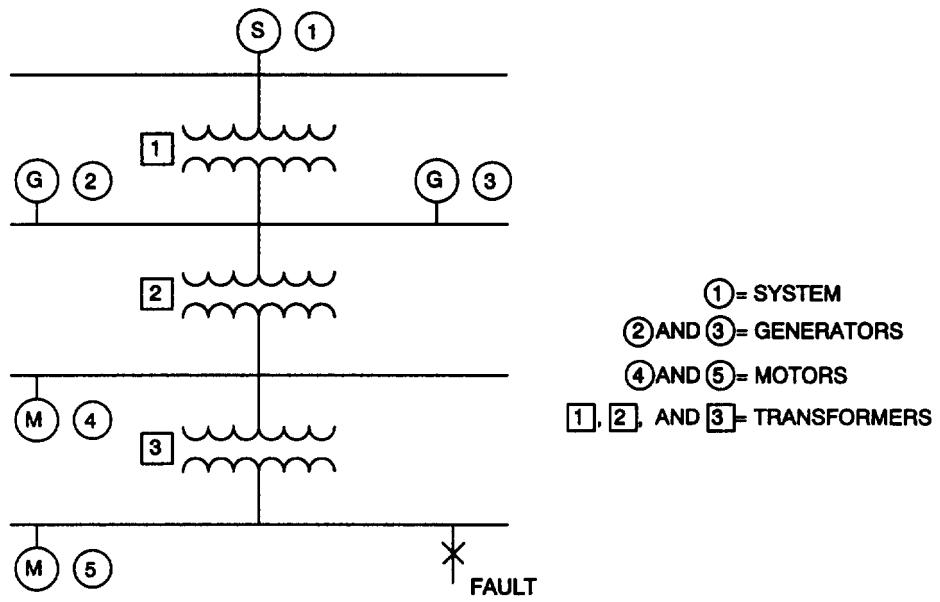


Figure 6.7(a) – Single-Line Diagram

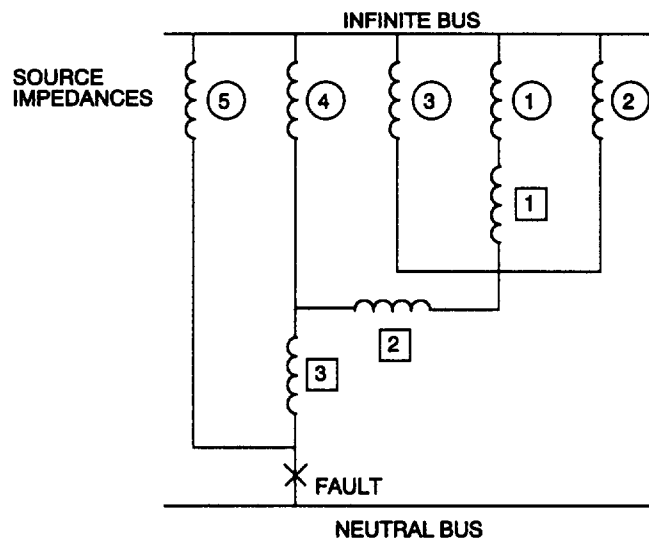
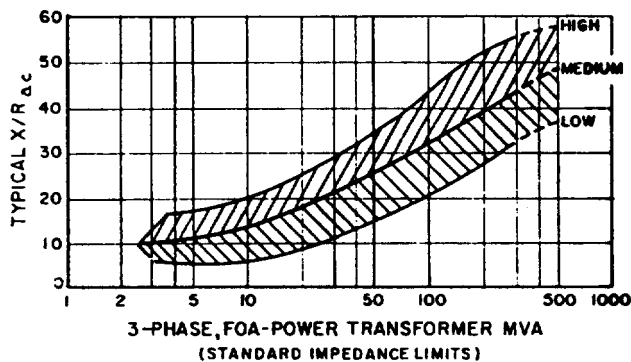


Figure 6.7(b) – Impedance Diagram



Based on class of transformer, obtain the proper factor from the table below. Multiply the transformer megavolt-ampere rating by this factor before using Fig 6.8 to obtain the typical X/R value.

Class	Rating in MVA	Factor
OA	all ratings	1.67
FA	up to 14.9	1.33
FA	16 and up	1.25
FOA	all ratings	1.0

Reprinted from IEEE C37.010-1979 [5]

Figure 6.8 — X/R Ratio for Power Transformers

then

$$\begin{aligned} E_{pu} &= pu \text{ V} = kV/\text{base kV} \\ I_{pu} &= pu \text{ A} = A/\text{base A} \\ Z_{pu} &= pu \text{ } \Omega = \Omega/\text{base } \Omega \end{aligned}$$

where

$$\begin{aligned} I_{base} &= \text{base current (A)} = \frac{\text{base kVA}}{\sqrt{3} \text{ base kV}} \\ Z_{base} &= \text{base impedance (}\Omega\text{)} = \frac{(\text{base kV})^2 1000}{\text{base kVA}} \end{aligned}$$

Impedances of individual power system elements are usually obtained in forms that require conversion to the selected bases for a per-unit calculation. Ohms can be converted directly to per-unit from base kV and base kVA by using the following formula:

$$Z_{pu} = \frac{\Omega (\text{base kVA})}{(\text{base kV})^2 1000}$$

Per-unit impedances derived in bases other than chosen bases can be converted to the new selected bases by using:

$$Z_{pu(\text{new base})} = Z_{pu(\text{old base})} \cdot \frac{(\text{old base kV})^2}{(\text{new base kV})^2} \cdot \frac{(\text{new base kVA})}{(\text{old base kVA})}$$

Sometimes impedance may be expressed in percent impedance. To obtain per-unit impedance from percent impedance (both given in terms of the same bases):

$$Z_{\text{pu}} = \frac{Z(\%)}{100}$$

6.8.6 Transformers

6.8.6.1 Equivalent Circuit

For fault calculations, a transformer equivalent circuit neglecting excitation current and core losses is used. A three-phase, two-winding transformer is modeled as a simple series impedance Z_{HX} for each phase. This impedance (Z_{HX}) is called the short-circuit or leakage impedance. The equivalent circuit for one phase is shown in Fig 6.9(a). This impedance is nearly always given in per unit (or percent) based on the transformer rating. The per-unit values of Z_{HX} are approximately constant for transformers of a given size and design. Tables 6.2 and 6.3 give average values of transformer impedances and can be used if actual nameplate data is not available. Likewise, a three-phase, three-winding transformer takes on a similar form, as shown in Fig 6.9(b), where Z_{HX} , Z_{HY} , and Z_{XY} are the short-circuit impedances referred to the primary circuit of the transformer.

The transformer impedances Z_{H} , Z_{X} , and Z_{Y} are the impedances of the primary, secondary, and tertiary windings referred to the primary circuit and are shown in Fig 6.9(b). They are derived as follows:

$$Z_{\text{H}} = 1/2 [Z_{\text{HX}} + Z_{\text{HY}} - Z_{\text{XY}}]$$

$$Z_{\text{X}} = 1/2 [Z_{\text{HX}} - Z_{\text{HY}} + Z_{\text{XY}}]$$

$$Z_{\text{Y}} = 1/2 [-Z_{\text{HX}} + Z_{\text{HY}} + Z_{\text{XY}}]$$

Table 6.2 — Standard Impedance Values for Three Phase Transformers

Secondary Unit Substation Transformers		
High-Voltage Rating (V)	kVA Rating	Percent Impedance Voltage
2400–13 800	112.5–224	Not less than 2.0
2400–13 800	300–500	Not less than 4.5
2400–13 800	750–2500	6.75*
22 900	All	6.75*
34 400	All	7.25
Liquid-Immersed Transformers, 501-30 000 kVA		
High-Voltage Rating (V)	Low-Voltage 480 V	Low-Voltage 2400 V and Above
2400–22 900	6.75*	6.5 [†]
26 400, 34 400	7.25	6.0
43 800	7.75	6.5
67 000		7.0
115 000		7.5
138 000		8.0

NOTES:

1 — Ratings separated by hyphens indicate that all intervening standard ratings are included. Ratings separated by a comma indicate that only those listed are included.

2 — Percent impedance voltages are at self-cooled rating and as measured on rated voltage connection.

*Three phase transformers 5000 kVA and smaller with high-voltage windings rated 25 kV and below are commonly used in industrial applications and are normally built with impedance voltages of 5.75%.

[†]Three phase transformers 5000 kVA and smaller with high-voltage windings rated 25 V and below are commonly used in industrial applications and are normally built with impedance voltages of 5.5%.

Table 6.3 — Transformer Impedances

(a)
Typical Per Unit R and X Values for Indoor, Open Dry-Type 150 °C Rise Transformers Rated From 15–2500 kVA, Three Phase, 2.5–15 kV Primaries, 208, 240, 480, 600 V Wye or Delta Secondaries

kVA	HV (kV)	LV (V)	%Z	X/R	R	X
15	2.5–15	208Y–600	3.00	0.5	0.027	0.013
30	2.5–15	208Y–600	5.00	1.0	0.035	0.035
45	2.5–15	208Y–600	5.00	1.0	0.035	0.036
75	2.5–15	208Y–600	5.50	2.0	0.025	0.049
112.5	2.5–15	208Y–600	4.50	1.5	0.025	0.037
150	2.5–15	208Y–600	4.50	2.0	0.020	0.040
225	2.5–15	208Y–600	5.00	2.5	0.019	0.046
300	2.5–15	208Y–600	5.00	2.8	0.017	0.047
500	2.5–15	208Y–600	5.00	4.0	0.012	0.049
750	2.5–15	208Y–600	5.75	2.0	0.026	0.051
1000	2.5–15	208Y–600	5.75	2.5	0.021	0.053
1000	2.5–15	480Y	8.00	3.8	0.021	0.077
1500	2.5–15	208Y–600	5.75	3.3	0.017	0.055
2000	2.5–15	208Y–600	5.75	4.0	0.014	0.056
2500	2.5–15	208Y–600	5.75	4.3	0.013	0.056

(b)
Typical Per Unit R and X Values for Indoor, Open Dry-Type 150 °C Rise Transformers Rated From 25–500 kVA, Single Phase, 5 and 15 kV Primaries, 120/240 V Wye or Delta Secondaries

kVA	HV (kV)	LV (kV)	%Z	X/R	R	X
25	5		4	2	0.018	0.036
to	to	120/240	to	to		
500	15		6	4	0.015	0.058

(c)
Typical Range of Per Unit Values for Indoor, Open Dry-Type 150 °C Rise Transformers Rated From 15–500 kVA, Three Phase, 480 V Primary, 208 V Wye Secondary

kVA	%Z	X/R	R	X
15	4.5	0.41	0.042	0.017
to	to	to		
500	5.9	2.09	0.025	0.053

(d)
**Typical Range of Per Unit R and X Values for Indoor, Open Dry-Type 150 °C Rise Transformers
 Rated From 5–167 kVA, Single Phase, 240 · 480 V, 480 V, 600 V Primaries, 120/240 V Wye
 Secondaries**

kVA	HV (kV)	LV (kV)	%Z	X/R	R	X
5	240-480		3	0.6	0.026	0.015
to	to	120/240	to	to		
167	600		6	2.0	0.027	0.051

This data is for dry-type transformers. Refer to NEMA AB1-1986 [14], Table A1, for information on liquid-filled, self-cooled transformers.

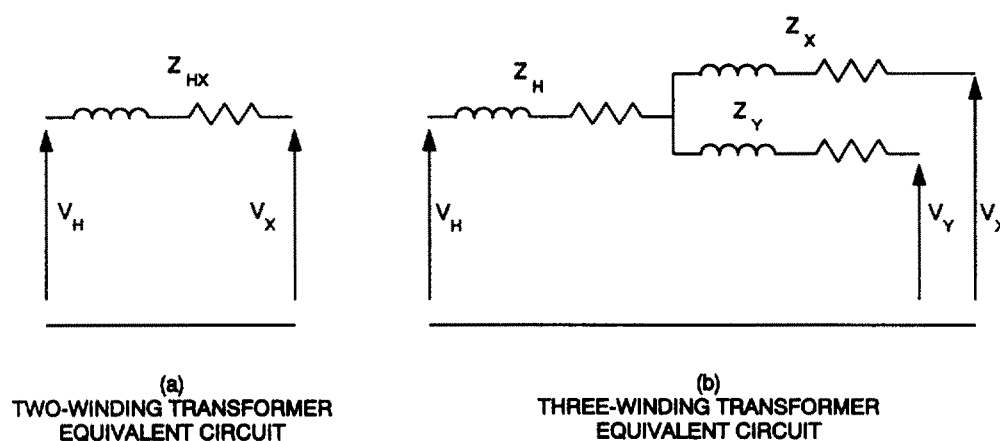


Figure 6.9 — Equivalent Transformer Circuit

6.8.6.2 Transformer Impedances

The manufacturing tolerance permitted by standards for the transformer short-circuit impedance is $\pm 7.5\%$ of the specified value for a two-winding transformer and $\pm 10.0\%$ for a three-winding transformer or autotransformer. During the design stage, the minimum transformer short-circuit impedance should be used in the fault calculation to determine the worst-case fault current.

Usually, during the initial design of the plant, the tap settings for the transformer are not known. If the tap settings are not known, then the transformer short-circuit impedance(s) at nominal tap should be used.

6.8.6.3 Transformer Voltage Bases

Voltage bases selected for the transformer windings (and for the systems they are connected to) must be in the same ratio as the transformer winding rated voltages. Otherwise, the transformers cannot be represented by simple series impedances.

6.8.7 Equivalent Impedance

After the considerations of 6.8.1 thru 6.8.6 have been addressed, the impedance diagram can be reduced to a single equivalent impedance and used in an Ohm's law relation. The basis for finding an equivalent impedance comes from Thevenin's theorem, which translates a complex circuit into a circuit represented as a single voltage source and a

single impedance. The single voltage source is equal to the voltage at the fault point before the fault occurs, and the equivalent impedance is equal to the impedance measured at the point of application of the fault looking back into the circuit with all the generated voltages short-circuited and current sources open-circuited. The equivalent impedance of Fig 6.7 is found by combining impedances between the infinite bus and the neutral bus.

Some systems are such that they cannot be reduced by merely combining series and parallel impedances. It is sometimes necessary to convert a delta impedance to an equivalent wye impedance by the formulas in Fig 6.10. By these conversions, any commonly encountered system impedance diagram can be reduced by the methods of series and parallel combinations.

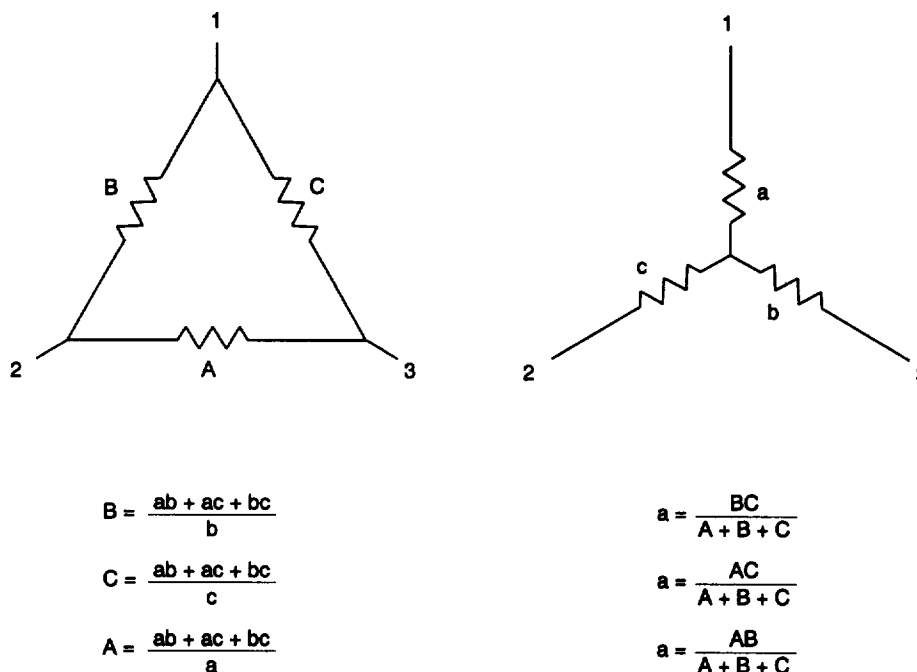


Figure 6.10 —Y - Δ Conversions

6.8.8 System X/R Ratio

Often the X/R ratio of the system is needed in fault calculations. Although there is no way of representing the sum of various exponentially decaying currents by a single exponential wave form, the X/R ratio of the circuit is conservatively approximated by a single time constant. This is done by drawing two separate impedance diagrams: one consisting solely of all reactance in the circuit, the other consisting solely of all resistance in the circuit. The X/R ratio is then simply the equivalent reactance of the circuit (neglecting all resistance) divided by the equivalent resistance of the circuit (neglecting all reactance).

6.8.9 Symmetrical Fault Current Determination

After the equivalent per-unit reactance has been determined, it is simply a matter of applying Ohm's law to determine the symmetrical fault current (in A):

$$I_{\text{sym, rms}} = \frac{E_{\text{pu}}}{Z_{\text{pu}}} \cdot I_{\text{base}}$$

where

- E_{pu} = highest typical operating (prefault) voltage (in pu) that occurs at the fault location. This will yield conservative results that are more exact than if a lower operating voltage were assumed.
- I_{base} = base current at fault location voltage level.
- Z_{pu} = equivalent impedance of system at fault location.
- $I_{sym,rms}$ = symmetrical rms fault current, in A.

The symmetrical rms fault current should be used in comparing the system available fault duty with the short-circuit capabilities of equipment, unless a multiplier must be used to correct for special conditions. Fault level is often expressed in symmetrical short-circuit kilovolt-amperes, which is related to per-unit impedance by the equation:

$$\text{short-circuit kVA} = \frac{E_{pu}^2}{Z_{pu}} \cdot (\text{kVA base})$$

Table 6.4 — Range and Typical Values of X/R Ratios of System Components

System Component	Range	Typical Values
Large generators and hydrogen-cooled synchronous condensers	40–120	80
Small generators and synchronous motors	See Fig 6.11	—
Power transformers	See Figs 6.8 and 6.9	—
Induction motors	See Fig 6.12	—
Reactors	40–120	80
Open wire lines	2–16	5
Underground cables	1–3	2

NOTE — Actual values should be obtained if practical.

6.8.10 Multipliers

The symmetrical short-circuit current found by Ohm's law often must be corrected for certain conditions that were not included in the treatment of reactance of the sources. Such factors that may alter the magnitude of calculated fault current used in the rating of breakers and fuses are

- 1) Time, i.e., determining the value of fault current at a given time after inception of the fault.
- 2) X/R ratio of circuit being different from X/R ratio at which device was tested.
- 3) The location of the fault relative to the generating source.
- 4) Current may be needed as an asymmetrical value for comparison with particular device rating.

A further discussion of this subject is given in 6.9.

6.8.11 Assumptions and Limitations

Before continuing with a detailed procedure for calculating fault currents, a consideration of the assumptions made so far in this section and the limitations imposed by these assumptions is examined to assure proper application of the outlined procedure. It is assumed that a three-phase bolted fault occurs on a symmetrical three-phase system with balanced symmetrical loading. Such an assumption allows a simplified analytical approach to fault calculations because the effects of mutual coupling between motor and transformer windings are balanced. This results in the treatment of a three-phase system as a single phase problem since each phase contains the same information. Such an assumption carries with it the following restraints:

- 1) The electric power system components must be of a symmetrical design pattern.
- 2) The electric loading imposed on the system must be balanced and symmetrical.

When these conditions are not essentially met, more complicated procedures of network analysis are needed that are beyond the scope of this document, but are covered in [18] and [B7], [B9], [B15], and [B16].

Another assumption made is that rotating machine reactance can be modeled as three distinct constant-valued reactances corresponding to three different time periods. Sometimes this assumption is not suitable for accurate calculations of fault current. A complete detailed analysis of rotating machine reactance may need to be included with the fault calculations. Reference [18] outlines a method for doing this.

In determining the X/R ratio of the network, X and R values are calculated independently as though the other component of the impedance were zero. Although a single exponential cannot equal the sum of two or more exponentials having different time constants, a reasonably close agreement can be obtained in a great majority of practical cases (see [5] and [B15]). The separate X and R reductions are simpler, conservative, and have the added benefit of giving the best approximation for the X/R ratio at the fault point.

When using Thevenin's theorem, it is assumed that the circuit is linear. In the discussion of machine reactance, it is seen that machine reactance is nonlinear, but it is assumed to be linear when constant values are assigned to it.

Multipliers applied to the calculated symmetrical current E/X are derived from theoretical and empirical considerations (see [5] and [16]). It is assumed that the network under consideration has the same typical electrical characteristics as the networks from which these constants were obtained.

6.9 AC Fault Calculation Procedure

This section examines four basic networks used for the fault currents most commonly desired:

- 1) *Fault Duty Type 1.* Interrupting duty of low-voltage circuit breakers, interrupting duty of fuses used on low-voltage circuits, fault duty for instantaneous relays on low-voltage circuits
- 2) *Fault Duty Type 2.* Momentary duty of medium-voltage circuit breakers, interrupting duty of power fuses on medium-voltage circuits, fault duties for instantaneous relays on medium-voltage circuits
- 3) *Fault Duty Type 3.* Interrupting duties of medium-voltage circuit breakers
- 4) *Fault Duty Type 4.* Short-circuit currents for time-delayed relays

The four networks have the same basic steps involved in calculating the fault duties, the differences being in which current sources to consider, which rotating machine reactance to use, and which multipliers to use to account for time and X/R ratios.

6.9.1 Fault Duty Type 1

This type of fault-duty calculation is used to select the interrupting duty of low-voltage circuit breakers and fuses as well as to select instantaneous relay settings. To make a low-voltage fault study, the steps of 6.8 are taken with the following exceptions and additions.

6.9.1.1 Motor Loads

- 1) All connected motors are considered as current sources and are modeled using their subtransient reactance.
- 2) When total motor load connected to a transformer is not known, assumptions are as follows:
 - a) *120 and 120 / 208 V.* Assume connected load is 50% lighting and 50% motor load (see [6] and [14]). Total single-phase loads will be modeled as a balanced three-phase load.
 - b) *240, 480, and 600 V.* Assume that all operating loads (other than the individual circuit being studied) are grouped at the transformer secondary bus and have a kVA rating (assume kVA equal to horsepower) of 100% of the transformer rating. In addition, assume that the load is comprised of 100% motor load and, in the absence of more exact information, that 100% of the motors are induction.

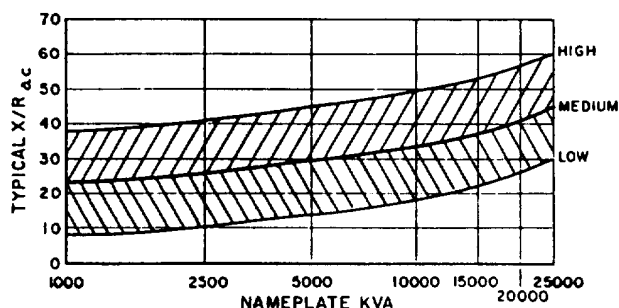
6.9.1.2 System Impedances

- 1) *Transformer Secondary Voltage System*
 - a) It is customary to use an assumed typical value for equivalent reactance of 25% either on the individual motor ratings, or on the total rating of a group of motors, expressed in kVA (see Table 6.1). (If only one motor is connected to the transformer, an equivalent reactance of 17% is used.)
 - b) Resistance of motors is found from X and X/R ratios (Figs 6.11 and 6.12), and from the equation $R = X / X/R$ (an X/R ratio of 6 is typical).
 - c) Lighting loads may be neglected.
- 2) *Transformer Primary Voltage System.* The contribution from the primary system should be equivalent to that calculated for its momentary duty. The X/R of the primary system is also needed. Then

$$Z_{\text{primary,pu}} = \text{base kVA} / \text{short-circuit kVA}$$

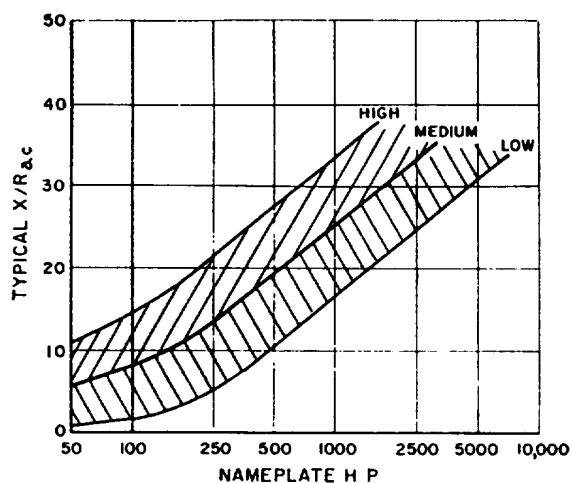
$$R_{\text{primary,pu}} = Z_{\text{primary,pu}} / \sqrt{1 + (X/R)^2}$$

$$X_p = (X/R_p)(R_p)$$



Reprinted from IEEE C37.010-1979 [5]

Figure 6.11 — X/R Range for Small Generators and Synchronous Motors (Solid Rotor and Salient Pole)



Reprinted from IEEE C37.010-1979 [5]

Figure 6.12 — X/R Range for Three Phase Induction Motors

- 3) *Others.* Circuit breakers, current transformers, and bus structure are usually neglected for ease in calculation. Accuracy of the calculation is not generally affected because the effects of the impedances are usually relatively small, and omitting them provides conservatively higher short-circuit currents. Transformer and cable impedances are included.

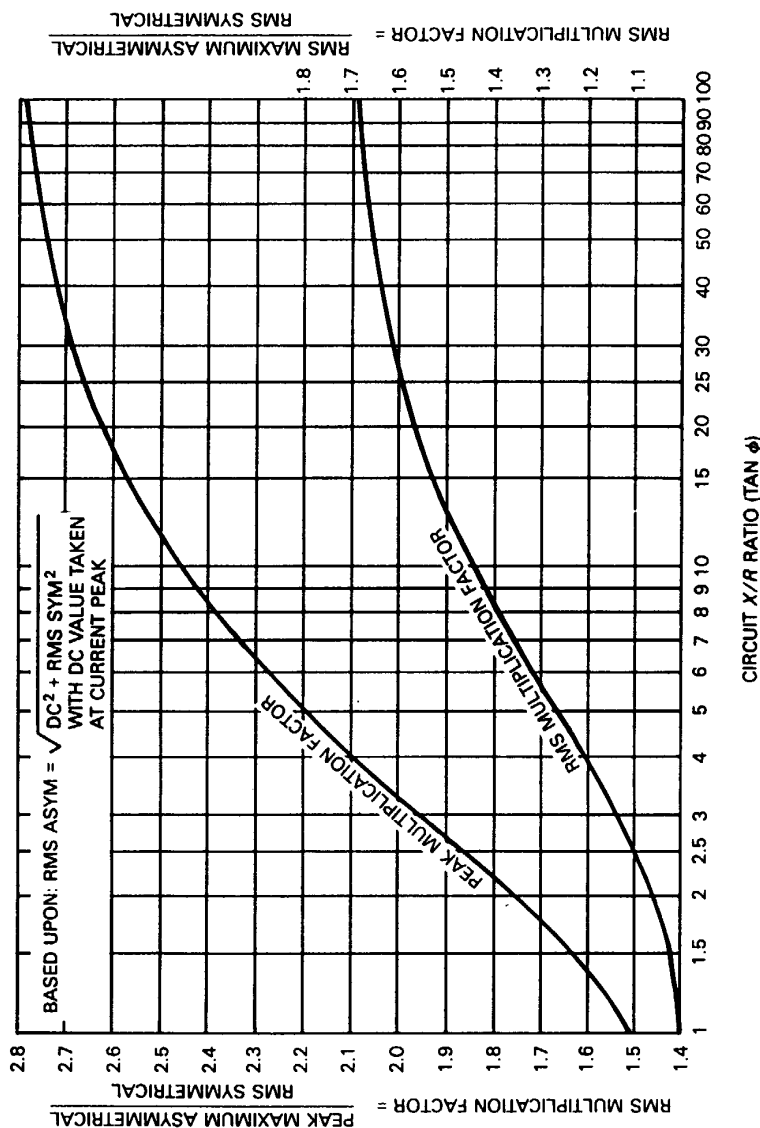
6.9.1.3 Multipliers

For low-voltage circuit breakers applied to systems with $X/R > 6.6$, a multiplier from Table 6.6 should be applied to the E/Z calculated value. This is because the breaker ratings are based on tests with a system $X/R = 6.6$ (see [6]).

Fuses are tested with $X/R = 15$ or an asymmetrical interrupting capability of 1.55 times the symmetrical current (see Fig 6.13). When the X/R of the circuit is different from 15 (see [17]), a multiplier to apply to the E/Z calculation can be derived from Fig 6.13 using

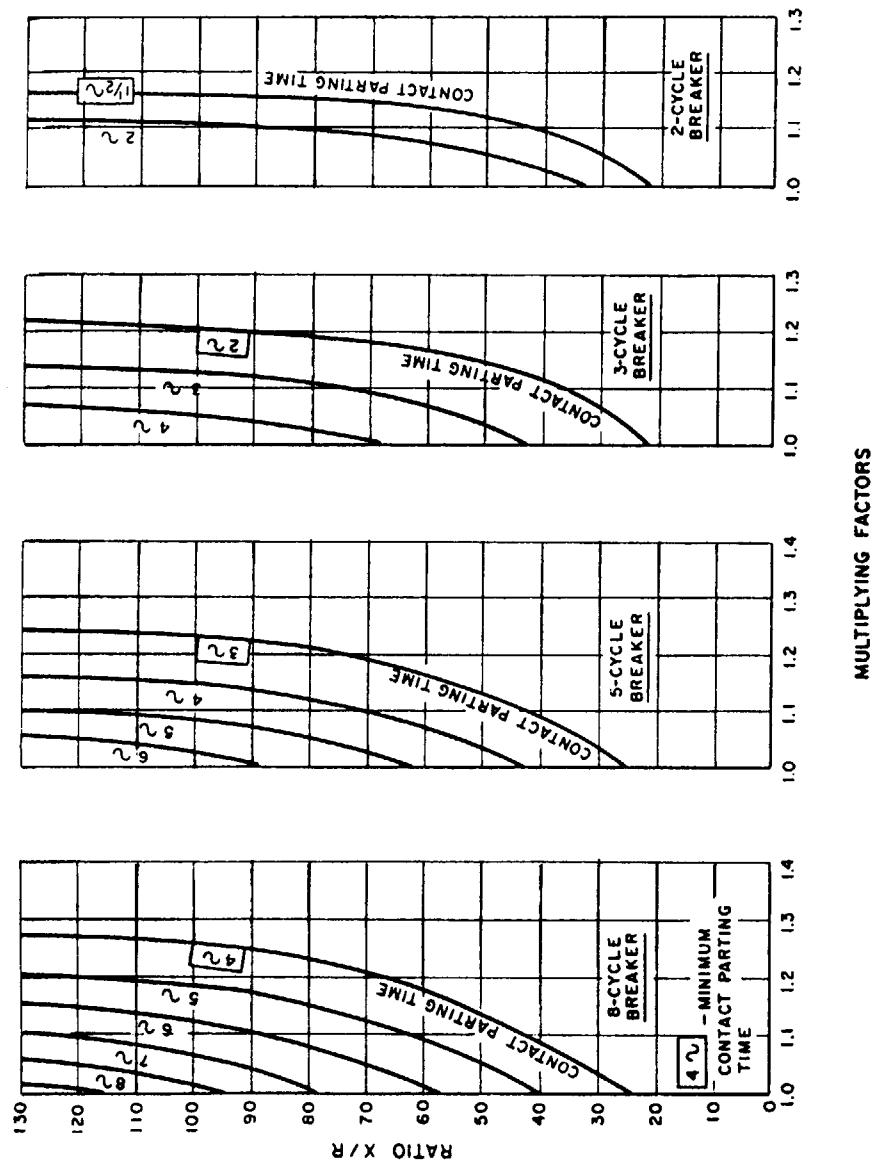
$$\text{multiplier} = \frac{\text{mult. factor (function of } X/R)}{1.55}$$

When calculating the minimum fault current for relay application, multipliers from Table 6.5 show the reduction of the E/Z calculation due to arcing (see [B4]).



Reprinted from IEEE C37.41-1988 [8]

Figure 6.13 – Relationship of X/R Ratio to Multiplication Factor



Reprinted from IEEE C37.010-1979 [5]

Figure 6.14 — Multiplying Factors for Three Phase Faults Fed Predominantly From Generators Through No More Than One Transformation

Table 6.5 — Approximate Minimum Values of Arcing-Fault Current (in Per Unit Bolted Values)

Type of Fault	Nominal 600V	System 480V	Voltage 208V
Three phase	0.94	0.89	0.12

Table 6.6 — Selection of Multiplying Factor

System Short-Circuit Power Factor Percent	System X/R Ratio	Multiplying Factor for Calculated Short Circuit Current
15	6.6	1.00
12	8.27	1.04
10	9.95	1.07
8.5	11.72	1.09
7	14.25	1.11
5	20.0	1.15

6.9.2 Fault Duty Type 2

This type of fault-duty calculation is used to select the momentary duty of medium-voltage circuit breakers, the interrupting rating of medium-voltage power fuses, and instantaneous relay settings. To make a medium-voltage fault calculation for the initial asymmetrical rms current, the steps of 6.8 are taken with the following exceptions and additions:

- 1) All resistance in network is neglected and reduces E/Z to E/X .
- 2) Machine reactances are modified by the momentary multipliers in Table 6.7.
- 3) The closing and latching capability of circuit breakers is given in total asymmetrical current, and E/X must be multiplied by 1.6. In cases where $X/R > 25$, 1.6 may be too low. The appropriate multiplier is then found from

$$MF = \sqrt{1 + 2e^{-2\pi R/X}}$$

- 4) The same MF is used for power fuses and relays when current is needed in asymmetrical rms amperes.

Table 6.7 — Rotating-Machine Reactance Multipliers

Type of Rotating Machine	Momentary	Interrupting
All turbine generators, all hydrogenerators with amortisseur windings, all condensers	$1.0 X''_d$	$1.0 X''_d$
Hydrogenerators without amortisseur windings	$0.75 X'_d$	$0.75 X'_d$
All synchronous motors	$1.0 X''_d$	$1.5 X''_d$
Induction Motors	$1.0 X''_d$	$1.5 X''_d$
Above 1000 hp at 1800 r/min		
Above 250 hp at 3600 r/min	$1.0 X''_d$	$1.5 X''_d$
All others, 50 hp and above r/min	$1.2 X''_d$	$3.0 X''_d$
All smaller than 50 hp	Neglect	Neglect

6.9.3 Fault Duty Type 3

This type of fault-duty calculation is used to select the interrupting duty of medium-voltage circuit breakers. The procedure to follow is outlined in Fig 6.17 (see [5] and [17]). The steps are explained below:

- 1) *Compute X.* X is the corresponding lowest value of system reactance (determined with R assumed to be zero) as viewed from the fault point with all rotating machines represented by the appropriate reactance values. Table 6.1 gives the typical reactance values for machines. Table 6.7 gives the interrupting multipliers for these machine reactances (to account for decay of ac short-circuit contribution). Tables 6.2 and 6.3 give transformer impedances.
- 2) *Compute E/X .* E is the highest available prefault voltage possible at the fault location before occurrence of the fault.
- 3) *$E/X \leq 0.8 \times \text{Selected Breakers Rating}$.* If the calculated symmetrical rms fault current is less than 80% of the selected breaker three-phase symmetrical interrupting rating, then all that is needed is to check on its momentary duty (see 6.9.2). If the symmetrical rms fault current is greater than 80% of the breaker interrupting rating, then further computation is required for a more accurate fault current calculation.
- 4,5) *Compute X/R .* If the X/R ratio is known to be less than 15, then no computation is necessary and the procedure goes to step (6). But, in most cases, this is not known and the calculation is needed. Table 6.8 shows typical X/R ratios of a system. It rarely is less than 15. X is the same as described in Step 1. R , for transformers, can be found using the values of X from Tables 6.2 and 6.3 and the values of X/R from Fig 6.8 in the equation [$R = X / (X/R)$]. R , for machines, can be found using the same equation with values of X from Table 6.1 and the values of X/R from Figs 6.11, 6.12, and Table 6.4.

Table 6.8 — Equivalent System X/R Ratio at Typical Locations (For Quick Approximations)

	Type of Circuit	Range
(1)	Synchronous machines connected directly to the bus or through reactors	40–120
(2)	Synchronous machines connected through transformers rated 100 MVA and larger	40–60
(3)	Synchronous machines connected through transformers rated 100 MVA for each three phase bank	30–50
(4)	Remote synchronous machines connected through transformers rated 100 MVA or larger for each three phase bank, where the transformers provide 90% or more of the total equivalent impedance to the fault point	30–50
(5)	Remote synchronous machines connected through transformers rated 10– 100 MVA for each three phase bank, where the transformers provide 90% or more of the total equivalent impedance to the fault point	15–40
(6)	Remote synchronous machines connected through other types of circuits, such as transformers rated 10 MVA or smaller for each three phase bank, transmission lines, distribution feeders, etc.	15 or less

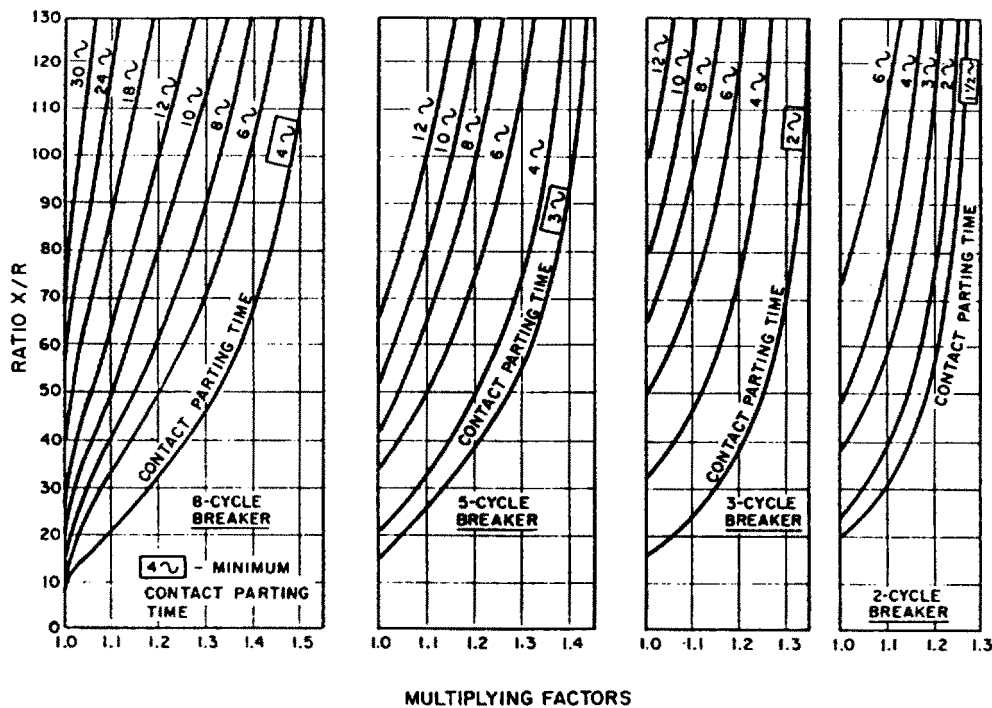
- 6) If the X/R is less than or equal to 15, the interrupting duty found is good for 100% of the symmetrical interrupting capability (circuit breakers are tested with an X/R ratio of 15).
- 7) If the ratio is larger than 15, a correction must be applied to the calculated current to account for current decrement. The rate of decrement depends on the location of the fault from points of generation.
- 8) For three-phase faults fed predominantly from generators through no more than one transformation or a per-unit reactance external to the generator that is less than 1.5 times the generator per-unit subtransient reactance on a common kVA base, a multiplier from Fig 6.14 is applied to the E/X calculation. This figure includes the effects of ac decay of generators as well as dc decay. This value depends on the breaker used, the X/R ratio of the circuit, and the contact parting time (assuming a relay time of 1/2 c).

- 9) For three-phase faults that are fed predominantly from generators through two or more transformations or a per-unit reactance external to the generator that is equal to or exceeds 1.5 times the generator per-unit subtransient reactance (on a common kVA base), a multiplying factor is found from Fig 6.15. This value depends on factors discussed in step (8). This curve accounts for dc decay and neglects ac decay, since the transformers or external impedance may mask the effects of the ac decay (see 6.3.2).
- 10) In some cases, the sources of current will be neither totally local (feed the fault through more than one transformation, see Fig 6.14) nor totally remote (see Fig 6.15). In this case, an interpolation from the two curves is needed (see [17]) depending on a NACD (no alternating-current decrement) ratio defined as

$$\text{NACD ratio} = \frac{\text{sum of NACD sources}}{E/X \text{ for interrupting network}}$$

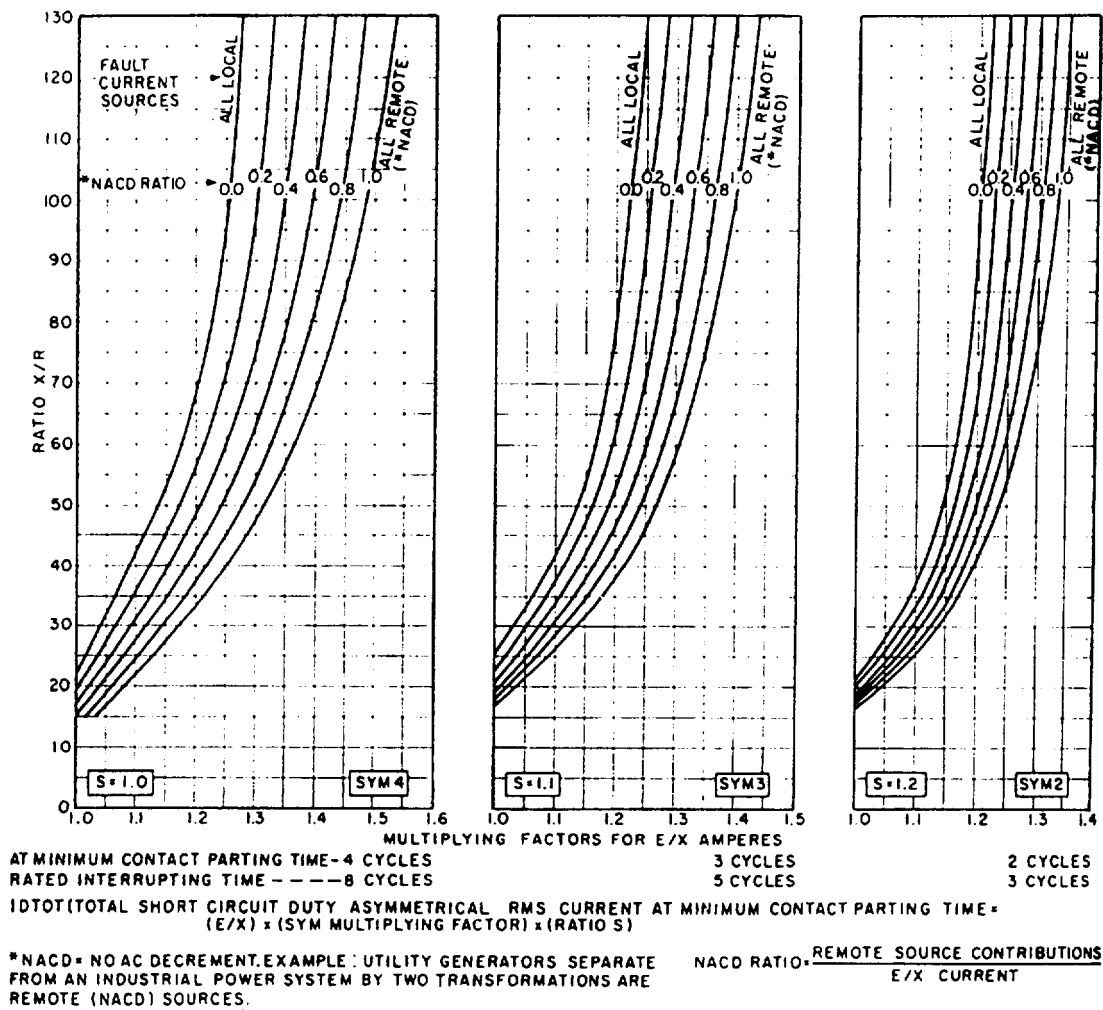
Fig 6.16 shows an interpolation for circuit breakers with different contact parting times.

- 11) Finally, the corrected I_{sc} is to be compared to the selected breaker interrupting capacity to make sure I_{sc} does not exceed the interrupting capacity.



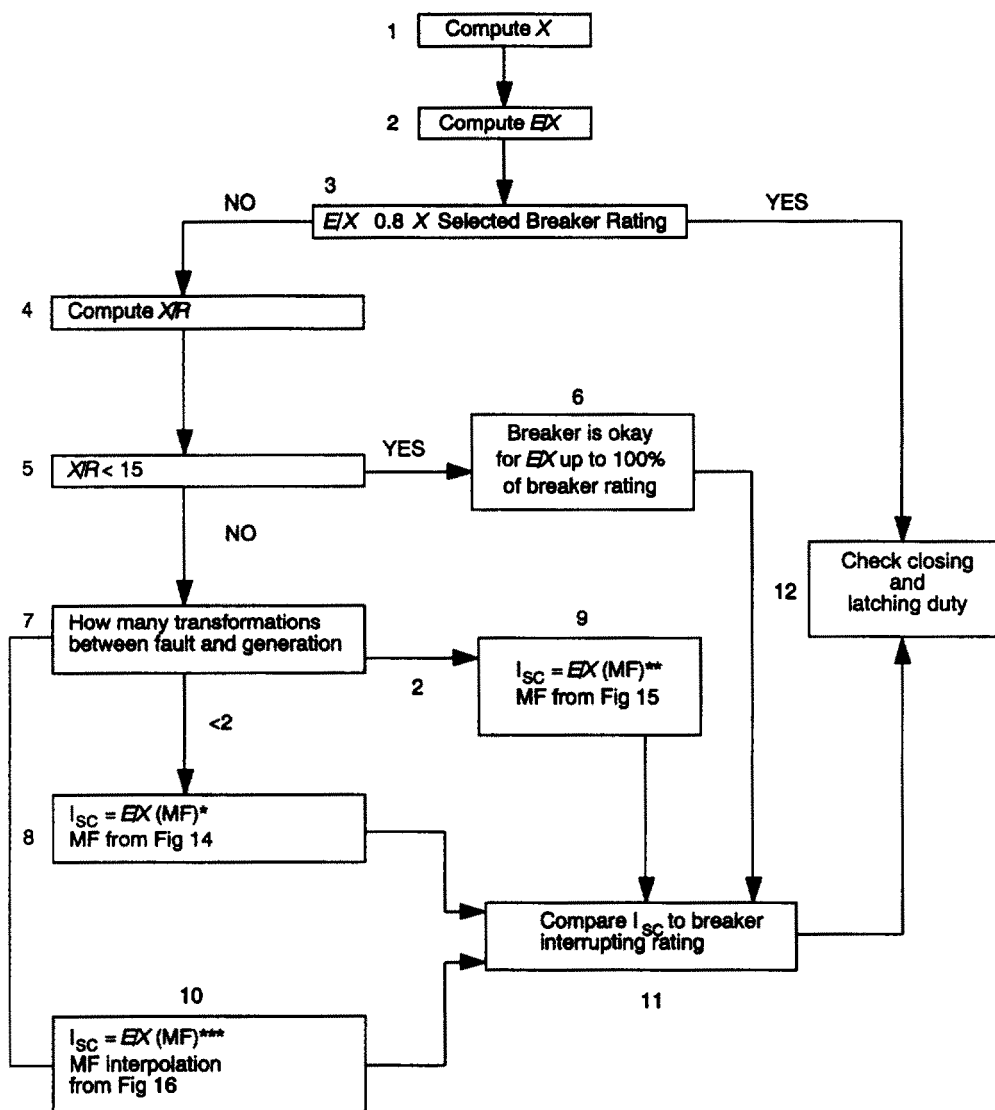
Reprinted from IEEE C37.010-1979 [5]

Figure 6.15 – Multiplying Factors for Three Phase Faults Fed Predominantly Through Two or More Transformers



Reprinted from Huening, W. C., Jr. "Interpretation of New American National Standards for Power Circuit Breaker Applications," *IEEE Transactions on Industry and General Applications*, vol. IGA-5, No. 5, Sep./Oct. 1969, pp. 501-523.

Figure 6.16 — Fig 6.16 Multiplying Factors (Symmetrical Current Rating Basis) for Three Phase Faults Fed From Both Local and Remote Generators



* FAULT FED FROM LOCAL GENERATION

** FAULT FED FROM REMOTE GENERATION

*** FAULT FED FROM BOTH LOCAL AND REMOTE GENERATION

Figure 6.17 — Medium Voltage Circuit Breaker Interrupting Duty Procedure

6.9.4 Fault Duty Type 4

This type of fault-duty calculation is used to apply time-delay relays. When calculating minimum fault currents to activate time-delay relays, the following assumptions can be used:

- 1) Ignore all motors and generators that may have either been disconnected or whose current has decayed to zero.
- 2) Use transient reactance of all generators.
- 3) If the delay exceeds 10 c, assume that the dc component has decayed to zero.

6.10 DC System Fault Current

Power generation plants contain dc electrical systems in addition to ac electrical systems. These systems are used generally as a backup to the ac system to provide an instantaneous source of emergency power when normal power fails.

The treatment of faults on a dc system is inherently different from the treatment of faults on an ac system and therefore warrants close attention. The sources of fault current, the fault current waveforms, and the equipment used to interrupt and isolate faults are discussed in this section. In addition, a procedure for calculating expected dc fault current magnitudes is presented.

6.10.1 Sources of DC Fault Current

There are four primary sources of dc fault current:

- 1) DC motors
- 2) DC generators
- 3) Rectifiers
- 4) Batteries

Each source of fault current needs to be examined in order to determine its contribution to the total fault current.

6.10.1.1 Motor and Generators

A general characteristic curve for short-circuit current from a generator or motor is shown in Fig 6.18. A machine terminal fault causes short-circuit current to rise at an essentially constant rate equivalent to voltage divided by unsaturated machine inductance. This rate of rise persists until the fault current has reached approximately two-thirds of its maximum value. At that time, modifying effects tend to change the rate of rise to conform to an exponential curve. The current stays at its maximum value for a period of time and then decays to a steady-state value (zero magnitude if the machine is self-excited, shunt wound). The time required for the current to decay to the sustained value is dependent upon the time constant of the exciting windings, which usually ranges from 0.1 to 1.0 s.

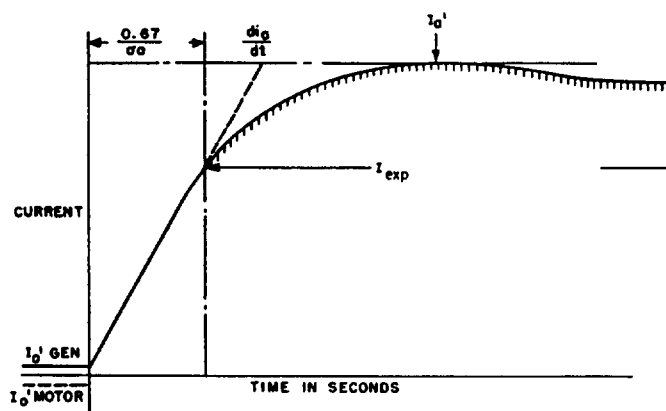


Figure 6.18 — Typical Short Circuit Characteristics of a DC Generator or Motor

The maximum current that a generator or motor can produce depends on its effective voltage at the instant before short circuit, its load prior to short circuit, its speed, and its effective resistance. This current is expressed by the equation

$$I_a' = \frac{e_o}{r_d}$$

where

- e_o = per-unit machine armature electromotive force prior to short circuit
 r'_d = per-unit transient resistance of the armature circuit
 I'_a = per-unit maximum fault current from the machine

The per-unit transient resistance of the armature circuit resistance (r'_d) for dc machines should be obtained from the manufacturer. All values of r'_d assume, for base speed and voltage, zero external resistance and no initial load.

The initial load current affects the magnitude of the short-circuit current. This can be introduced as a correction factor for the per-unit short-circuit current calculated from r'_d . The correction factor is added to the calculated current for machines operating as generators and is subtracted for motors. The magnitude of this correction equals the initial load current expressed in pu. The effect of initial load current prior to short circuit is a minor influence on heavy short-circuit currents and usually is not considered in fault calculations.

The initial rate of rise of the faulted machine current, in pu, is given by

$$\frac{di_a}{dt} = \frac{P N_1 e_o}{19.1 C_x} \text{ per-unit rated A/s}$$

where

- P = number of poles
 N_1 = base or minimum rated speed, in rpm
 e_o = armature generated voltage before short circuit, in pu
 C_x = characteristics constant for a particular class of machine

Values of C_x should be obtained from the manufacturer. e_o is assumed to be equal to 1, which is a practical and conservative assumption.

The duration of the constant rate of rise of current is obtained by finding the value of time corresponding to a current value of two-thirds of maximum current, or

$$t_a = \frac{0.67}{r'_d (di_a/dt)}$$

For modeling purposes, it is convenient to use the armature circuit unsaturated inductance. In such cases,

$$L'_a = \frac{19.1 C_x V_1}{P N_1 I_a} \text{ (in H)}$$

where

- I_a = machine rated current, in A
 V_1 = rated machine voltage, in V

6.10.1.2 Rectifiers (Battery Chargers)

The maximum fault current can be obtained from the manufacturer, or, if not available, a maximum fault current equal to the current limit value should be used.

6.10.1.3 Battery

The equivalent circuit of the battery is represented by the series combination of the internal resistance (R_A) of the battery, the resistance (R_C) of the conductor that connects the cells together, the inductance (L_C) of the conductors, and battery internal voltage (E_B).

The cell internal resistance should be obtained from the manufacturer. R_C and L_C depend on the conductor size, length, and composition. The battery internal voltage used should be obtained from the manufacturer and should be the lowest value to which the voltage will drop when the cell is suddenly placed under a heavy load. The charger will go into current limit and will not be able to hold cell voltage at its normal service value.

6.10.2 Circuit Breakers

Low-voltage dc power circuit breakers are classified into three types:

- 1) *General purpose.* Usually does not prevent fault current from rising to its sustained value.
- 2) *Semi-high-speed.* Limits the magnitude of the fault current by breaking the circuit within .03 s.
- 3) *High-speed.* Limits the magnitude of the fault current by breaking the circuit within .01 s.

Short-circuit ratings of these breakers can be found in IEEE C37.14-1979 [7].

In addition to power circuit breakers, dc circuits can be interrupted by molded-case air circuit breakers (see NEMA AB1-1966 [14]).

6.10.3 Total DC Fault Current

The total fault current flowing to the short-circuit location is comprised of the sum of the fault current contributed by the individual sources of current described previously.

When multiple sources are connected to a bus with negligible resistance, and a fault occurs on the bus, it is assumed that one source has no effect on the other source, and the total short-circuit current can be determined by constructing a current time curve for each source and adding the curves graphically.

In most practical cases, a short-circuit will result in the current from all of the sources flowing together through some of the same system elements. Since the currents share a common path, the calculation of the currents should take the entire system into account at all times.

6.10.4 DC Fault Calculation Procedure

The procedure for calculating dc faults closely parallels ac faults. A single-line diagram is needed that shows all relevant circuit elements. A decision must be made on the worst-case fault location in order to determine the maximum stresses on equipment. This may require the calculation of fault currents assuming that the fault occurs at a number of different points. A resistance diagram is developed showing the internal resistance of all sources and other system components. The total maximum short-circuit current is then calculated by using the system equivalent resistance in the following expression:

$$I_T = E/R_{eq} \text{ (in A)}$$

where

E	= system voltage, in V
R_{eq}	= equivalent system resistance, in Ω
I_T	= total maximum short-circuit current, in A

In addition to the resistance diagram, an inductance diagram is needed to obtain the rate of rise of total current. The inductance diagram is handled in the same manner as the resistance diagram. The inductances are assumed constant and are combined as parallel or series elements until one equivalent inductance is obtained to represent the entire system from the point of short circuit back to the source. This equivalent inductance is then used to calculate the initial rate of rise:

$$\frac{di_T}{dt} = \frac{E}{L_{eq}} \text{ (in A/s)}$$

where

$$\begin{aligned} E &= \text{system voltage, in V} \\ L_{eq} &= \text{equivalent system inductance, in H} \\ i_T &= \text{instantaneous value of } I_{TOTAL} \end{aligned}$$

Based on the maximum current determined from the resistance, and the initial rate of rise of the current determined from the inductance diagram, an approximate current-time curve for the total short-circuit can be constructed. This approximate curve is based on the assumption that the total current will have a current-time curve that can be represented by a simple exponential curve. The time constant is given by the expression:

$$T_T = \frac{L_{eq}}{R_{eq}} \text{ (in s)}$$

This current-time curve will accurately represent the actual short-circuit current when the parallel branches in the system all have the same L/R ratio. Different L/R ratios in the parallel branches of the system will result in different rates of current build-up in the branches. The total current will then be a complex exponential curve. In the usual case, the current-time curve calculated by assuming the current to follow a simple exponential curve will be as accurate as required.

An example dc short-circuit current calculation is presented in Section A3.

6.11 Bibliography

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Annex A (Informative)

A1. Short-Circuit Current Calculation for a Generator

A1.1 Example of a Short-Circuit Current Calculation for an Unloaded Generator

If a three-phase fault occurs on the unloaded terminals of a synchronous generator with the machine constants below, what is the total generator fault current after 1.5 cycles? (Assume a prefault terminal voltage of 1.0 pu. Quadrature axis quantities are not needed in this calculation).

$$x_d'' = 0.210 \quad T_{do}'' = 0.043 \text{ s}$$

$$x_d' = 0.330 \quad T_{do}' = 7.26 \text{ s}$$

$$x_d = 1.820 \quad T_{a3} = 0.33 \text{ s}$$

Rating: 1600 MVA, 24 kV

Base: 100 MVA, 24 kV

$$\text{Base Current} = \frac{100\,000 \text{ kVA}}{\sqrt{3} \cdot 24} = 2.406 \text{ kA}$$

$$\text{Base Ohms} = \frac{(24)^2}{100} = 5.76 \text{ } \Omega$$

$$x_d'' = 0.21 \cdot \frac{100}{1600} = 0.01313 \text{ pu}$$

$$x_d' = 0.33 \cdot \frac{100}{1600} = 0.02063 \text{ pu}$$

$$x_d = 1.82 \cdot \frac{100}{1600} = 0.11375 \text{ pu}$$

The ac components of the generator current are

$$i_d'' = \frac{1}{x_d''} = 76.19 \text{ pu}$$

$$i_d' = \frac{1}{x_d'} = 48.485 \text{ pu}$$

$$i_d = \frac{1}{x_d} = 8.791 \text{ pu}$$

The time constants of the ac current are

$$T_d'' = \frac{x_d''}{x_d'} T_{do}'' = 0.0274 \text{ s} = 1.642 \text{ c}$$

$$T_d' = \frac{x_d'}{x_d} T_{do}' = 1.316 \text{ s} = 78.982 \text{ c}$$

Then, the ac component of fault current from the generator is

$$\begin{aligned} i_{ac}(gen) &= \left[(i_d'' - i_d') \varepsilon^{\frac{-t}{T_d'}} + (i_d' - i_d) \varepsilon^{\frac{-t}{T_d}} + i_d \right] \\ &= 27.705 \varepsilon^{\frac{-t}{1.642}} + 39.694 \varepsilon^{\frac{-t}{78.982}} + 8.791 \end{aligned}$$

At time $t = 1.5$ c, the ac component of generator current is

$$\begin{aligned} i_{ac}(gen) &= 27.705 \cdot 0.4011 + 39.694 \cdot 0.98119 + 8.791 \\ &= 58.851 \text{ pu on 100 MVA} \\ &= 58.851 \cdot \frac{100\,000 \text{ kVA}}{\sqrt{3} \cdot 24 \text{ kV}} \\ &= 141\,573 \text{ A} \end{aligned}$$

The dc component of generator current is

$$i_{dc}(gen) = \sqrt{2} \cdot 76.19 \varepsilon^{\frac{-t}{T_{a3}}}$$

where

$$T_{a3}, \text{ in c, is } T_{a3} = 0.33 \cdot 60 = 19.8 \text{ c}$$

Thus the dc component of generator current is

$$i_{dc}(gen) = 107.749 \varepsilon^{\frac{-t}{19.8}}$$

At time $t = 1.5$ c, this current is

$$\begin{aligned} i_{dc}(gen) &= 99.888 \text{ pu on 100 MVA base} \\ &= 240\,293 \text{ A} \end{aligned}$$

The approximate total rms current (the asymmetrical current) is

$$i_{total} = \sqrt{i_{ac}^2 + i_{dc}^2}$$

For this example, the total current is

$$\begin{aligned} i_{total} &= \sqrt{(141\,573)^2 + (240\,293)^2} \\ &= 278\,897 \text{ A} \end{aligned}$$

A1.2 Example of a Short-Circuit Current Calculation for a Loaded Generator

Using the data in the unloaded generator example, what is the total generator fault current after 1.5 c if a three-phase fault occurs on the terminals of a synchronous generator? The generator was initially loaded at 1000 MVA at a power factor of 0.8 lagging with a terminal voltage of 1 pu.

The internal pre-fault voltage behind the subtransient reactance is

$$E_i'' = \frac{\text{Terminal Voltage of Generator} + \text{Voltage Drop Across Subtransient Reactance}}$$

$$= 1 + j.01313 \frac{1000(.8 - j.6)}{100}$$

$$= 1.084 \angle 5.6^\circ$$

The internal prefault voltage behind the transient reactance is

$$E_i' = \frac{\text{Terminal Voltage of Generator} + \text{Voltage Drop Across Transient Reactance}}$$

$$= 1 + j.02063 \frac{1000(.8 - j.6)}{100}$$

$$= 1.136 \angle 8.4^\circ$$

The internal prefault voltage behind the synchronous reactance is

$$E_i = \frac{\text{Terminal Voltage of Generator} + \text{Voltage Drop Across Synchronous Reactance}}$$

$$= 1 + j.11375 \frac{1000(.8 - j.6)}{100}$$

$$= 1.913 \angle 28.4^\circ$$

The ac components of the generator current are

$$i_d'' = \frac{1.084}{.01313} = 82.56 \text{ pu}$$

$$i_d' = \frac{1.136}{.02063} = 55.07 \text{ pu}$$

$$i_d = \frac{1.913}{.11375} = 16.82 \text{ pu}$$

The time constants of the ac circuit are the same as before

$$T_d'' = 0.0274 \text{ s} = 1.642 \text{ c}$$

$$T_d' = 1.316 \text{ s} = 78.982 \text{ c}$$

The ac component of fault current from the generator is

$$i_{ac}(gen) = \left[(i_d'' - i_d') e^{\frac{-t}{T_d''}} + (i_d' - i_d) e^{\frac{-t}{T_d'}} + i_d \right]$$

$$= 27.49 e^{\frac{-t}{1.642}} + 38.25 e^{\frac{-t}{78.982}} + 16.82$$

At time $t = 1.5 \text{ c}$, the ac component of generator current is

$$i_{ac}(gen) = 27.49 \cdot .4011 + 38.25 \cdot .9812 + 16.82$$

$$= 65.38 \text{ pu on 100 MVA}$$

$$= 65.38 \cdot \frac{100\,000 \text{ kVA}}{\sqrt{3} \cdot 24 \text{ kV}}$$

$$= 157\,280 \text{ A}$$

The dc component of generator current is

$$i_{dc}(gen) = \sqrt{2} \cdot 82.56 e^{\frac{-t}{T_{a3}}}$$

where

T_{a3} , in cycles, is the same as before: $T_{a3} = 19.8$ c

Thus, the dc component of generator current is

$$i_{dc}(gen) = 116.76 e^{\frac{-t}{19.8}}$$

At time $t = 1.5$ c, this current is

$$\begin{aligned} i_{dc}(gen) &= 108.24 \text{ pu on 100 MVA base} \\ &= 260\,388 \text{ A} \end{aligned}$$

The approximate total rms current (the asymmetrical current) is

$$\begin{aligned} i_{total} &= \sqrt{i_{ac}^2 + i_{dc}^2} \\ &= \sqrt{(157\,280)^2 + (260\,388)^2} \\ &= 304\,202 \text{ A} \end{aligned}$$

A2. Example of a Short-Circuit Calculation for a Power System with Several Voltage Levels

The auxiliary power system of Fig A1 is used as an example for Fault Duty Type 1, Fault Duty Type 2, and Fault Duty Type 3 described in 6.9 of this guide.

The base chosen for this example for all per-unit power quantities throughout the system is 10 MVA. Voltage bases are different for different voltage levels, but all must be related by the turns ratio of interconnecting transformers. Also, the generator is initially unloaded.

A2.1 Fault Duty Type 2

Reactances of passive elements, obtained from Figure 6A.1, are listed in Data Calculation 1 (see A2.1.1).

Subtransient reactances of rotating machine sources of short-circuit current are listed in Data Calculation 2 (see A2.1.3) with conversions to per-unit.

Modified subtransient reactance of rotating machine sources of short-circuit current are listed in Data Calculation 3 (see A2.1.3). The multipliers are from Table 7.

A2.1.1 Data Calculation 1 — Passive-Element Reactances (in pu, 10 MVA Base)

$$\begin{aligned} \text{Transformer } T_1, X &= .11 (10/760) = .00145 \text{ pu, } X/R = 52, R = .00145/52 \\ &= 2.79 \cdot 10^{-5} \text{ pu} \\ \text{Transformer } T_2, Z_{HX} &= 0.21, Z_{HY} = 0.21, Z_{XY} = 0.42 \text{ (from 6.7.6.1)} \\ Z_H &= 1/2(.21 + .21 - 0.42) = 0 \\ Z_X &= 1/2(.21 - .21 + 0.42) = .21 \\ Z_Y &= 1/2(-.21 + .21 + 0.42) = .21 \end{aligned}$$

Convert to the 10 MVA transformer rating base

NOTE — Assume resistance is negligible, therefore $Z_H = X_H$, $Z_X = X_X$, $Z_Y = X_Y$

$$X_H = 0$$

$$X_Y = X_X = .21 \cdot \frac{10}{60} = .035 \text{ pu}$$

$$X/R = 32$$

$$R_H = 0$$

$$R_y = R_x = .035/32 = 10.9 \cdot 10^{-4} \text{ pu}$$

$$\begin{aligned} \text{Transformer } T_3, X &= .072 (10/1) = .72 \text{ pu} \\ X/R &= 6, R = .72/6 = .12 \text{ pu} \end{aligned}$$

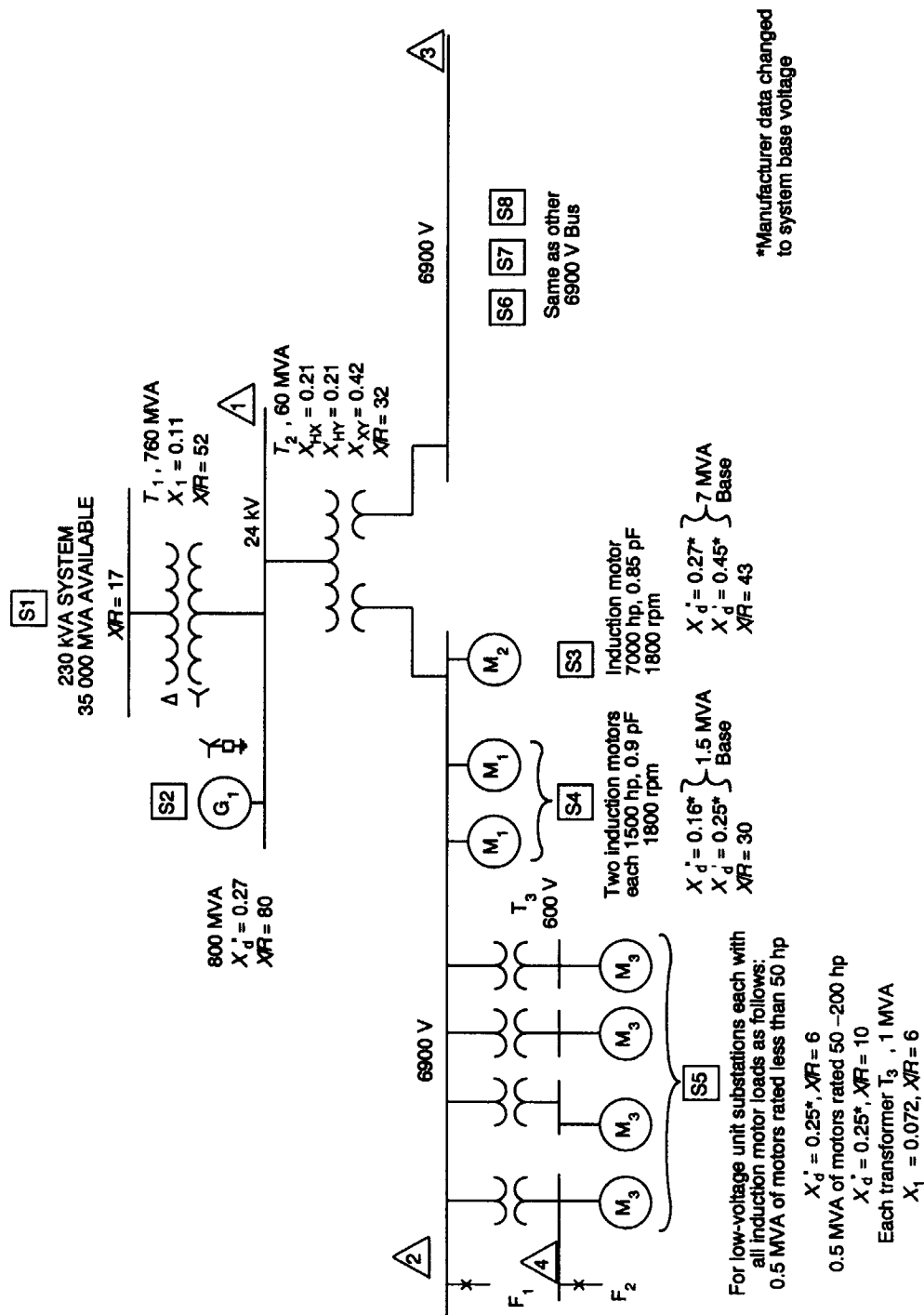


Figure 6A.1 – Single-Line Diagram of Generating Station Example

A2.1.2 Data Calculation 2 – Subtransient Reactances of Rotating Machines (in pu, 10 MVA Base)

230 kV system, $X = 1.0 (10/35000) = .000286$ pu

$$X/R = 17, R = .000286/17 = 1.68 \cdot 10^{-5} \text{ pu}$$

Generator 1, $X_d'' = 0.27 (10/800) = .00338$ pu

$$X/R = 80, R = .00338/80 = 4.23 \cdot 10^{-5} \text{ pu}$$

Induction motor M_1 , $X_d'' = .16 * (10/1.5) = 1.07$ pu

$$X/R = 30, R = 1.07/30 = 3.57 \cdot 10^{-2} \text{ pu}$$

Induction motor M_2 , $X_d'' = .27 * (10/7) = .386$ pu

$$X/R = 43, R = .386/43 = 8.98 \cdot 10^{-3} \text{ pu}$$

Low-voltage motor group, 0.5 MVA, less than 50 hp

$$X_d'' = 0.25 * (10/.5) = 5 \text{ pu}$$

$$X/R = 6, R = 5/6 = .833 \text{ pu}$$

Low-voltage motor group, 0.5 MVA, from 50-200 hp

$$X_d'' = 0.25 * (10/.5) = 5 \text{ pu}$$

*Manufacturer X_d'' data corrected to system base voltage by $\left(\frac{X_{dM}'' E_M^2}{E_s^2}\right)$ factor.

A2.1.3 Data Calculation 3 — Reactances for AC Medium-Voltage Circuit Breaker First-Cycle (Momentary) Duties

Reactance of source circuits for utility system, generators, and large motors (M_1 and M_2) are unchanged from Data Calculation 2 (see A2.1.3). Induction motors rated less than 50 hp are omitted. For the low-voltage motor group, 0.5 MVA, from 50-200 hp,

$$X = 1.2 X_d'' = 1.2(5) = 6.0 \text{ pu}$$

$$X/R = 10, R = 6.0/10 = .6 \text{ pu}$$

The circuit used for calculating the alternating currents that establish the first-cycle short-circuit duties is shown in Fig 6A.2.

The simplification of reactances to obtain one fault-point X at fault-point F_1 is shown in Fig 6A.3.

The symmetrical first-cycle (momentary) short-circuit rms current obtained at fault-point F_1 , is

$$\begin{aligned} I_{\text{base}} &= \frac{10 \text{ MVA}}{\sqrt{3} 6900 \text{ V}} \\ &= 836.7 \text{ A} \\ I_{\text{sym}} &= (1/.0306)(836.7) = 27.34 \text{ kA} \end{aligned}$$

assuming a prefault voltage of 1.0 pu.

The calculation for the equivalent fault point R is shown in Fig 6A.3(a).

The X/R ratio at F_1 is $.0306/9.35 \cdot 10^{-4} = 32.73$.

Since $X/R = 32.0 > 25$ the appropriate multiplication factor is

$$MF = \sqrt{1 + 2e^{-2\pi/32.73}}$$

$$= 1.63$$

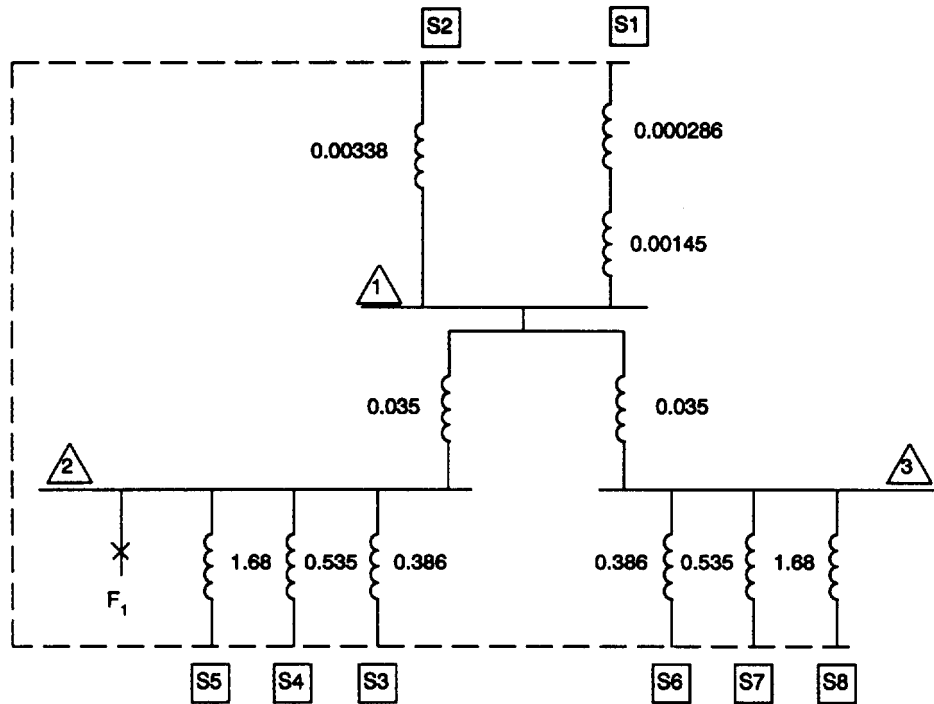


Figure 6A.2 — Impedance Diagram

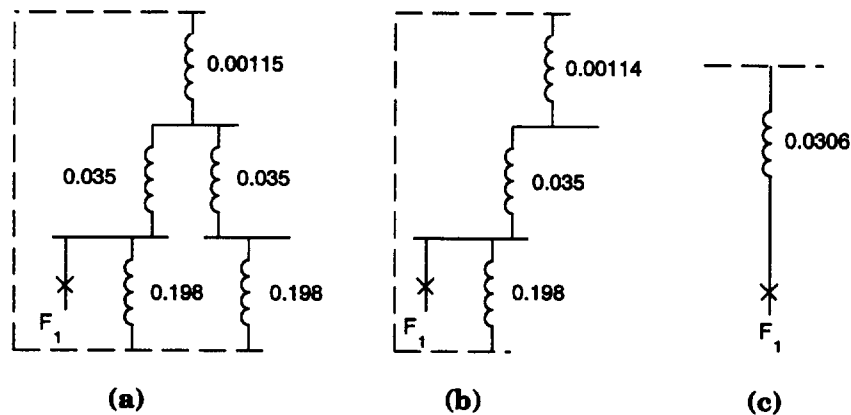


Figure 6A.3 — Circuit Reduction

A2.2 Fault Duty Type 3

Reactances, X/R ratios, and resistances for use in calculating ac medium-voltage circuit breaker interrupting short-circuit duties are listed in Fig 6A.1 and calculated in Data Calculation 4 (see A2.2.1).

The circuit for calculating the fault-point X is shown in Fig 6A.4.

The fault current at point F_1 is

$$E/X = (1/.0324) 836.7 = 25.8 \text{ kA}$$

A2.2.1 Data Calculation 4 — Reactances, X/R Ratios, and Resistances for AC Medium-Voltage Circuit Breaker Interrupting Short-Circuit Duties

Induction motor M_1 , using $X = 1.5X_d'' = 1.5(1.07) = 1.61 \text{ pu}$,

$$X/R = 30, R = 1.61/30 = .0535 \text{ pu}$$

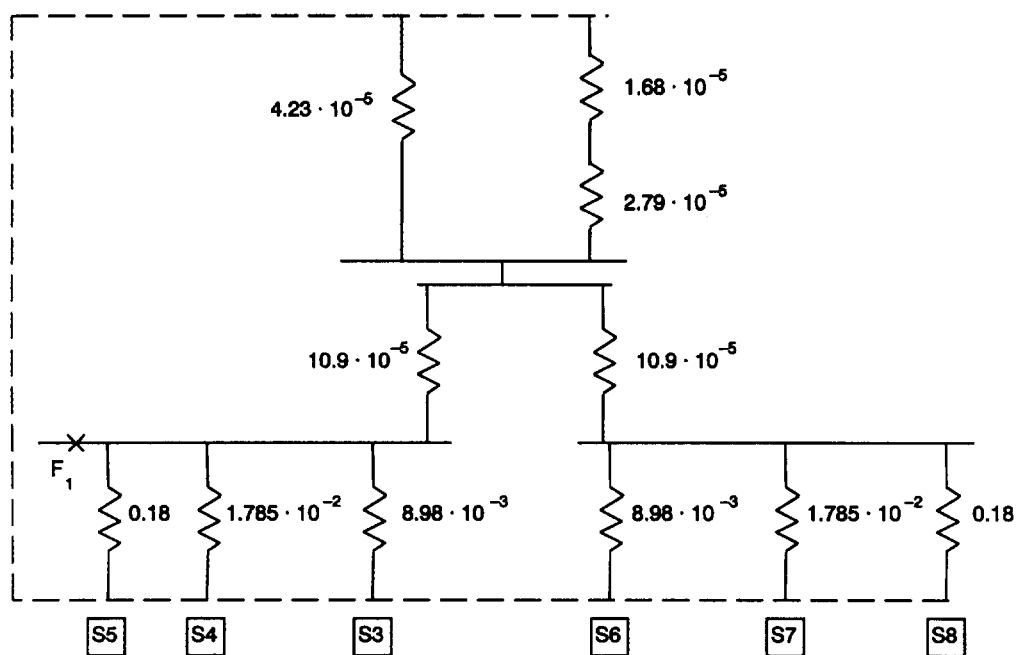
Induction motor M_2 , using $X = 1.5X_d'' = 1.5(.386) = 0.579 \text{ pu}$,

$$X/R = 43, R = 0.58/43 = 0.0135 \text{ pu}$$

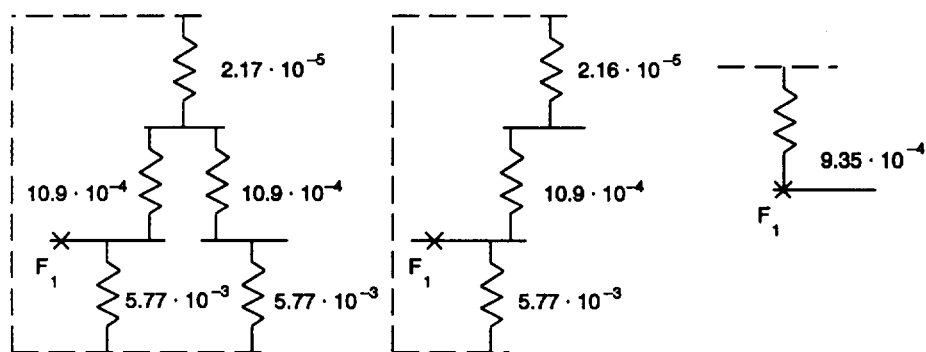
Low-voltage motor group below 50 hp is omitted

Low-voltage motor group, from 50 to 200 hp, using $X = 3.0X_d'' = 3(5) = 15 \text{ pu}$

$$X/R = 10, R = 15/10 = 1.5 \text{ pu}$$



(a)



(b)

(c)

(d)

Figure 6A.4 —Equivalent R Circuit Reduction

A.2.2.2 Data Calculation 5 — Reactances, X/R Ratios, and Resistances for AC Low-Voltage Circuit Breakers Short-Circuit Duties

Low-voltage motor group, less than 50 hp

$$X/R = 6, R = 5/6 = 0.833$$

Low-voltage motor group, from 50 to 200 hp

$$X/R = 10, R = 5/10 = 0.5$$

By the procedure outlined in Fig 6.17, if this value is greater than 80% of the selected breaker rating, the resistance circuit of Fig 6A.5 must be developed to obtain the X/R ratio at F_1 . The calculation for the equivalent fault point R is shown in Fig 6A.5.

The X/R ratio at F_1 is

$$X/R = .0324/.000987 = 32.8$$

Since this value is greater than 15, and the fault current sources are both remote and local, the NACD ratio is to be found. The equivalent circuit to find the current contribution by the remote sources (230 kV system) is shown in Fig 6A.6. The current from remote sources is

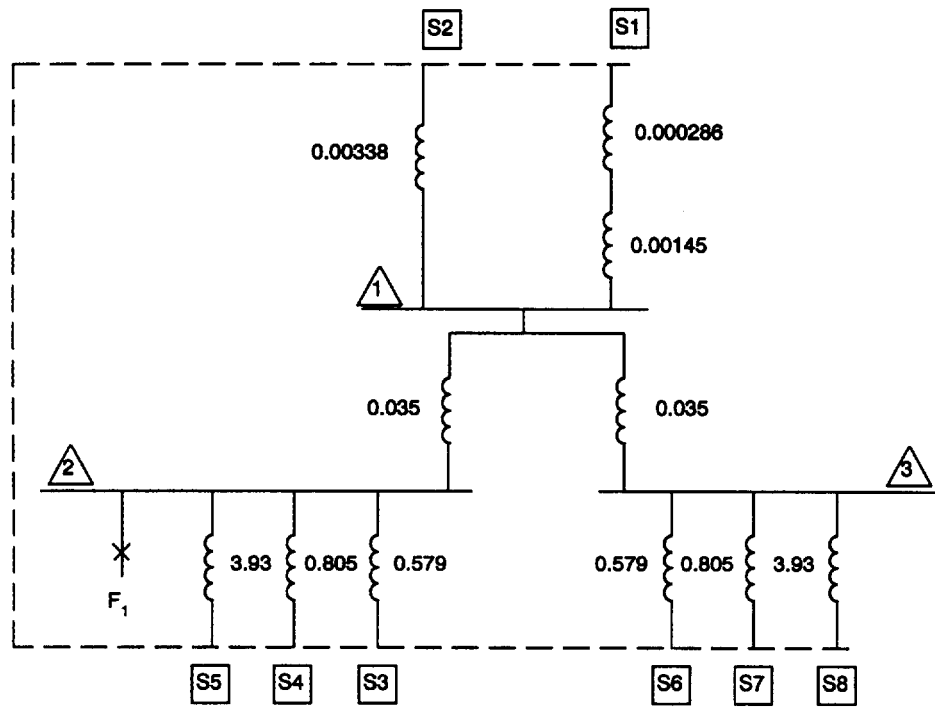
$$I_{\text{NACD}} = \left(\frac{1}{.0048} \right) 836.7 \frac{.00335}{.00335 + .035} = 15.23 \text{ kA}$$

and the NACD ratio is

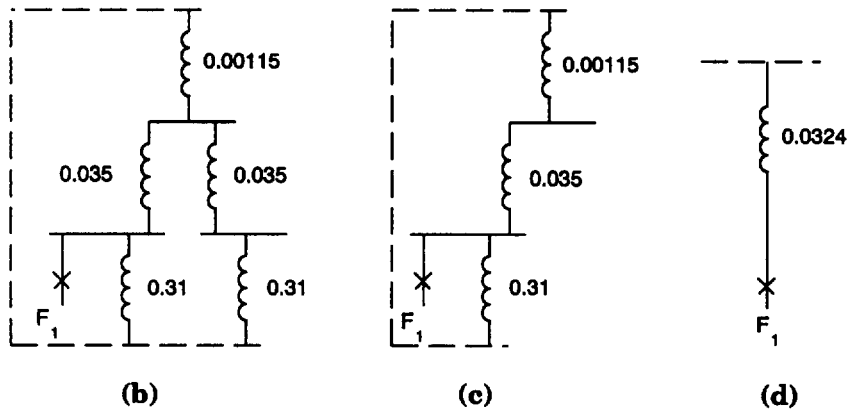
$$\text{NACD} = \frac{15.23 \text{ kA}}{25.8 \text{ kA}} = 0.590$$

Assuming the circuit breaker will have a 3 c parting time, Fig 6.16 shows a multiplier of 1.10. The symmetrical fault current that is interrupted is

$$\begin{aligned} I_{\text{sym}} &= 1.10(25.8 \text{ kA}) \\ &= 28.4 \text{ kA} \end{aligned}$$



(a)



(b)

(c)

(d)

Figure 6A.5 — Impedance Diagram

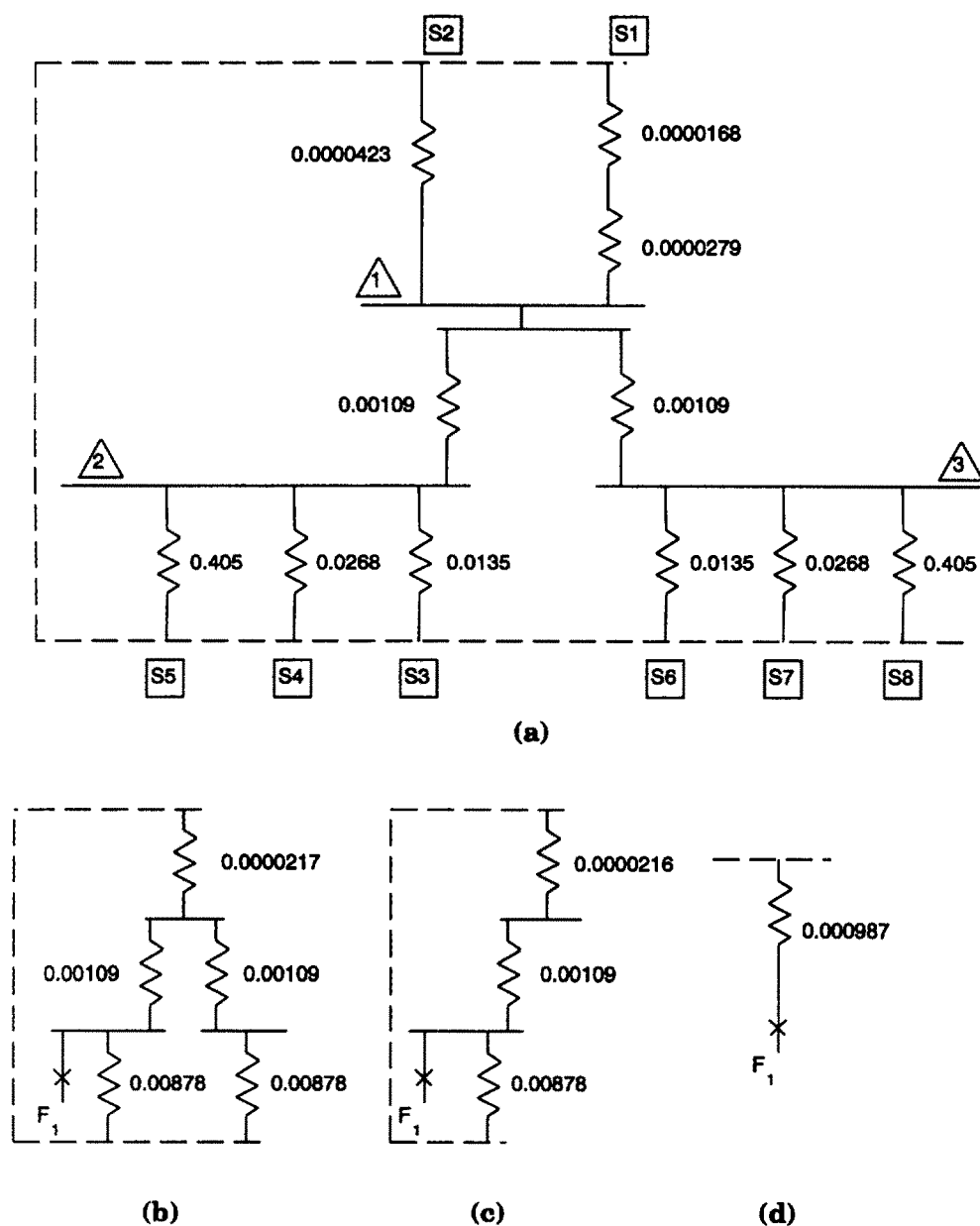


Figure 6A.6 —Equivalent R Circuit Reduction

A2.3 Fault Duty Type 1

The equivalent circuit for finding the short-circuit current at F_2 is shown in Fig 6A.7.

The 6900 V source contribution (primary system) is approximately equivalent to that calculated for its “momentary duty” in A2.1.

The transformer resistance and reactance values are listed in Data Calculation 1 (see A2.1.1) and Data Calculation 4 (see A2.2.1).

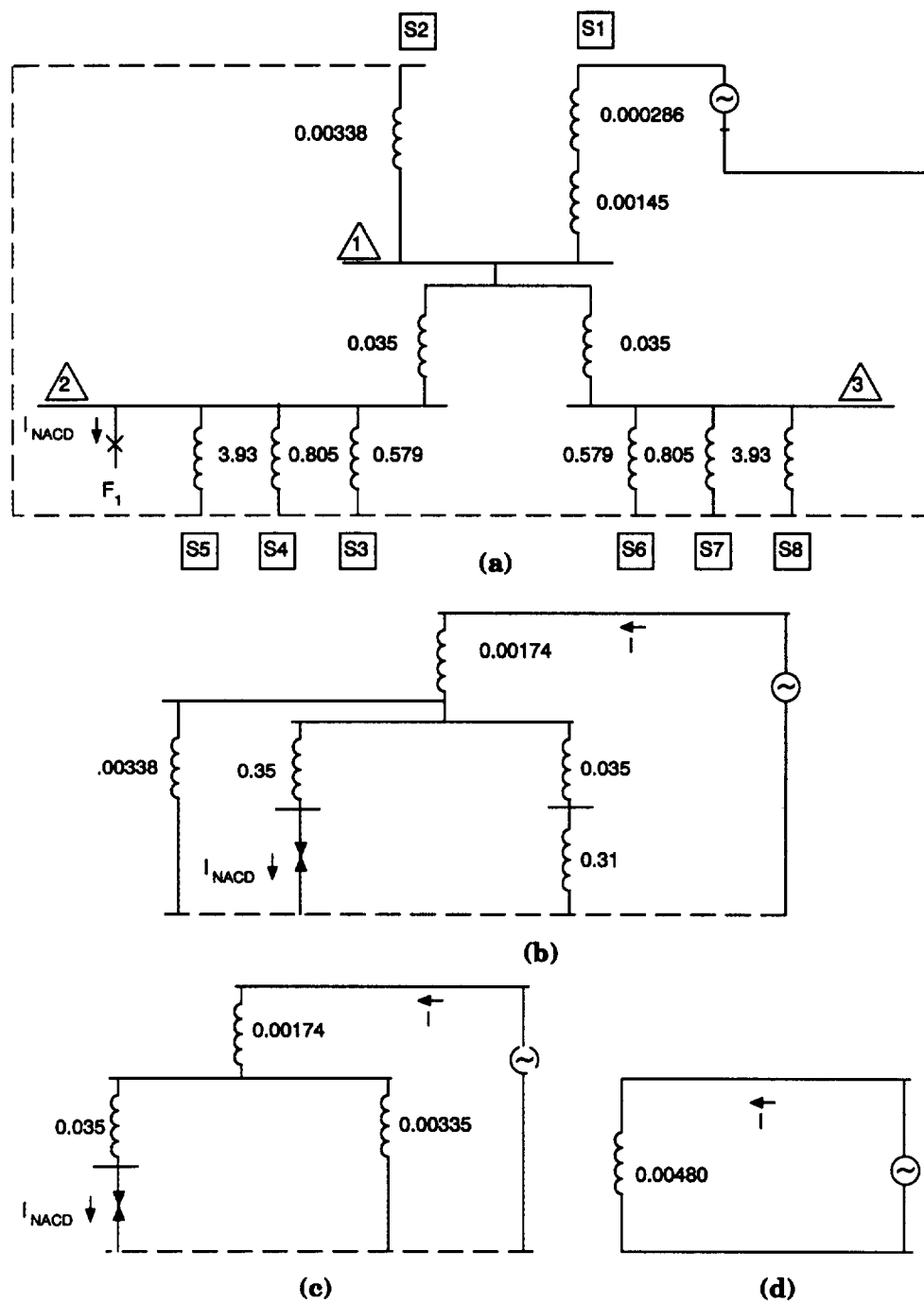


Figure 6A.7 — Impedance Diagram

The motor resistance and reactance values are listed in Data Calculation 5 (see A2.2.2).

The total impedance is

$$\begin{aligned}
 Z &= \sqrt{R^2 + X^2} \\
 &= \sqrt{(.0872)^2 + (.577)^2} \\
 &= 0.584 \text{ pu}
 \end{aligned}$$

The total three-phase symmetrical fault current at F_2 is

$$\begin{aligned} \text{Base amperes } X \text{ per unit current} &= \left(\frac{10\,000\,000}{\sqrt{3} \cdot 600} \right) \frac{1}{.584} \\ &= 16\,480 \text{ A} \end{aligned}$$

The X/R ratio is $X/R = .577/.0872 = 6.62$, which is sufficiently close to 6.6 to use a multiplier of 1.0.

A3. Example of Short-Circuit Current Calculation for a DC System

What is the magnitude of fault current flowing in the distribution center bus of Fig 6A.8 with equipment parameters listed below?

<u>Motor-Pole Face Winding</u>	<u>Battery</u>
250 V	internal resistance/cell = $1.81 \cdot 10^{-4} \Omega$ 120 cells
100 hp	
514 rpm	intercell connector resistance = $1.18 \cdot 10^{-5} \Omega$ 2 connectors/cell
4 pole	
400 A	
<u>Rectifier</u>	
maximum fault current = 1200 A	

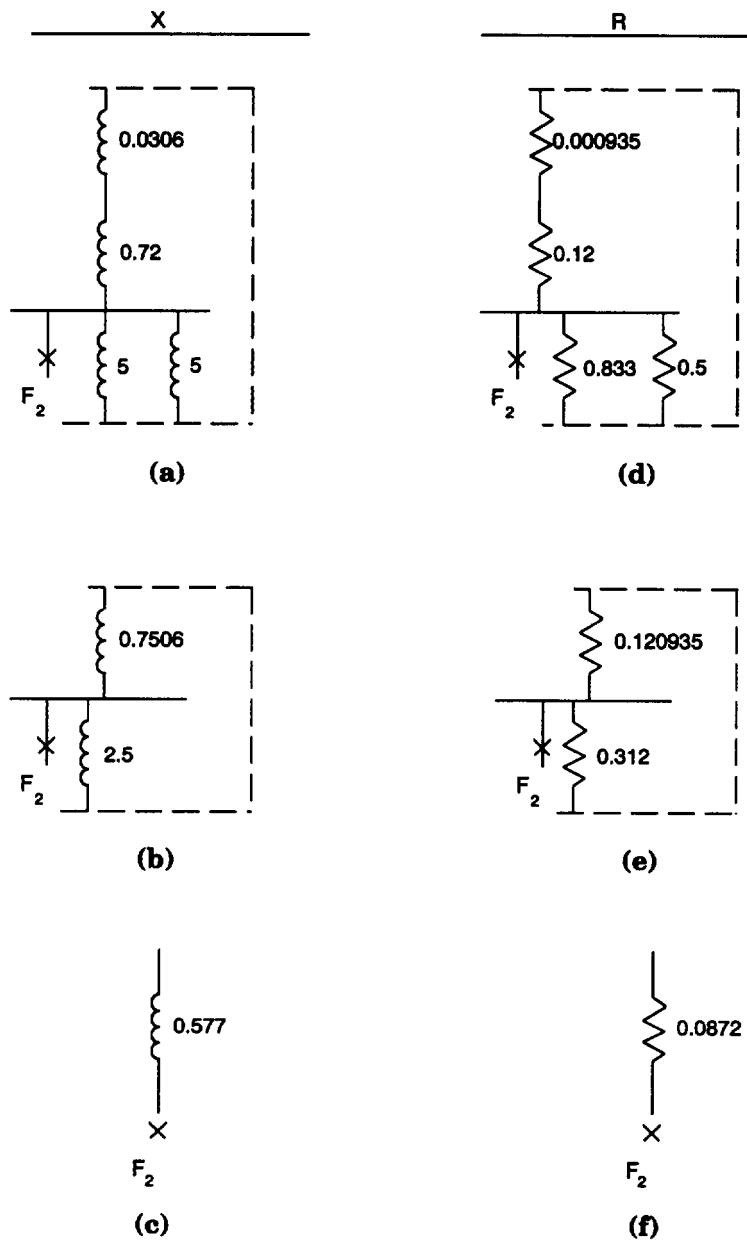


Figure 6A.8 — Impedance Diagram

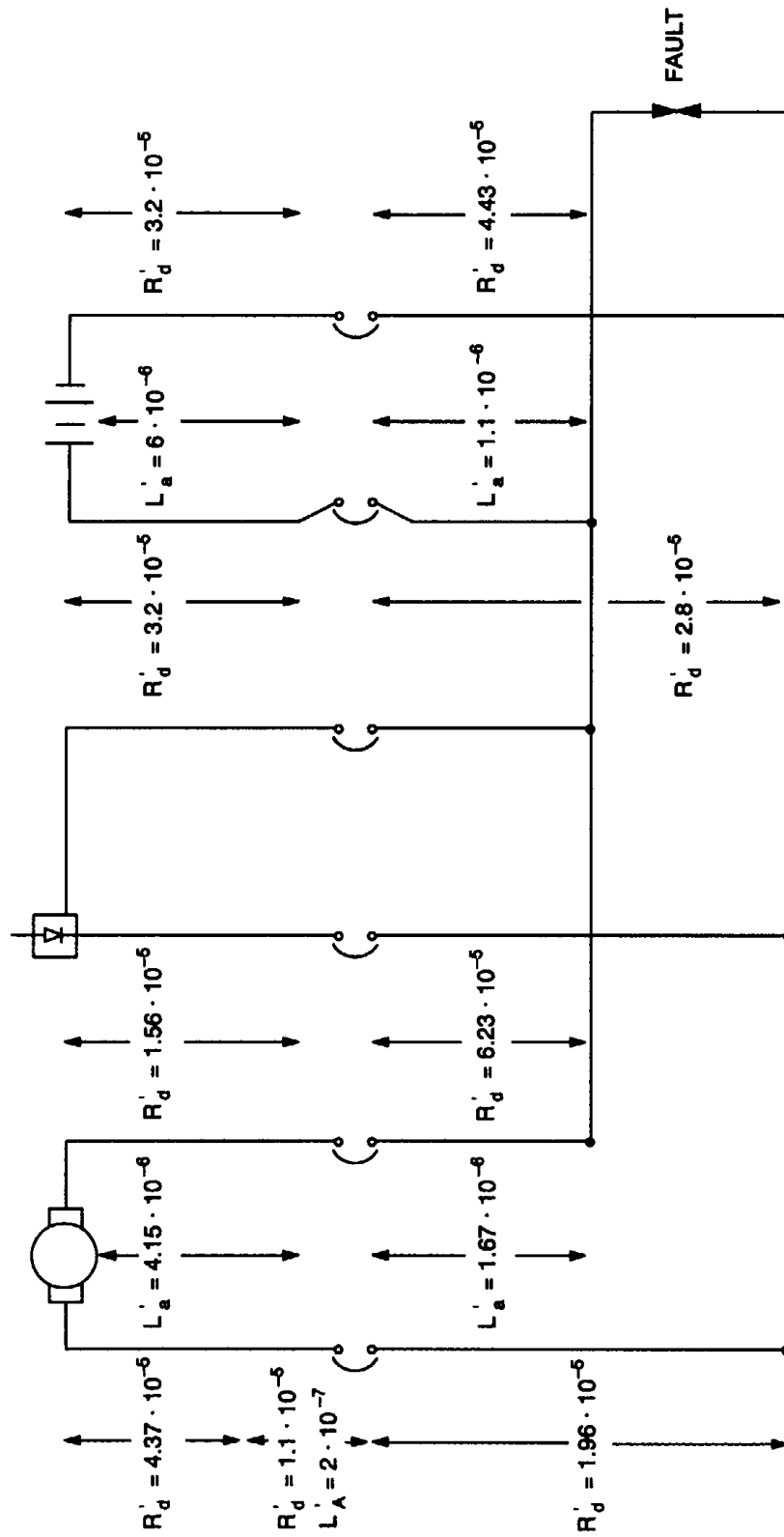


Figure 6A.9 – DC System

A3.1 Motor Contribution

$$\text{hp} \cdot \text{rpm} \cdot 10^{-5} = 100 \cdot 514 \cdot 10^{-5} = 0.514$$

from the manufacturer $r'_d = 0.12$

$$r'_d = .12 \left(\frac{250}{400} \right) = 0.075 \Omega$$

from the manufacturer $C_x = 0.1$

$$L'_a = \frac{19.1 C_x V_1}{PN_1 I_a} = \frac{19.1(.1)250}{4(514)400} = 5.81 \cdot 10^{-4} \text{ H}$$

$$R_{\text{eq}} = 0.075 + 4.37 \cdot 10^{-5} + 1.1 \cdot 10^{-5} + 1.96 \cdot 10^{-5} + 1.56 \cdot 10^{-5} + 1.1 \cdot 10^{-5} + 6.23 \cdot 10^{-5} = 0.0752 \Omega$$

$$L_{\text{eq}} = 5.81 \cdot 10^{-4} + 2 \cdot 10^{-7} + 4.15 \cdot 10^{-6} + 1.67 \cdot 10^{-6} + 2 \cdot 10^{-7} = 5.87 \cdot 10^{-4} \text{ H}$$

$$I'_a = \frac{E}{R_{\text{eq}}} = \frac{250}{.0752} = 3326 \text{ A}$$

$$\frac{di_a}{dt} = \frac{E}{L_{\text{eq}}} = \frac{250}{5.87 \cdot 10^{-4}} = 4.26 \cdot 10^5 \text{ A/s}$$

$$t_a = \frac{0.67 \cdot 250}{R_{\text{eq}} \frac{di_a}{dt}} = \frac{0.67 \cdot 250}{.0752(4.26 \cdot 10^5)} = 5.23 \cdot 10^{-3} \text{ s}$$

A3.2 Battery Contribution

$$R'_a = 120(1.81 \cdot 10^{-4}) - 0.02172 \Omega$$

$$R_{\text{intercell}} = 119 \frac{1.18 \cdot 10^{-5}}{2} = 7.021 \cdot 10^{-4} \Omega$$

$$R_a = R'_a + R_{\text{intercell}} = 0.0224 \Omega$$

$$R_c = 3.2 \cdot 10^{-5} + 2.8 \cdot 10^{-5} + 4.43 \cdot 10^{-5} + 3.2 \cdot 10^{-5} + 1.1 \cdot 10^{-5} + 1.1 \cdot 10^{-5} = 1.58 \cdot 10^{-4} \Omega$$

$$R_{\text{eq}} = R_a + R_c = 0.0224 + 1.58 \cdot 10^{-4} = .0226 \Omega$$

$$E_B = 120(2.055) = 246.6 \text{ V}$$

$$I'_a = \frac{246.6}{.0226} = 10\,921 \text{ A}$$

$$L_{\text{eq}} = 6.0 \cdot 10^{-6} + 1.1 \cdot 10^{-6} + 2 \cdot 10^{-7} + 2 \cdot 10^{-7} = 7.5 \cdot 10^{-6} \text{ H}$$

A3.3 Total Contribution

The maximum possible fault current that the distribution center bus can experience is the sum of the peak current contribution from each current source, or

$$\begin{aligned} I_{\max} &= 3326 + 10\,921 + 1200 \\ &= 15\,447 \text{ A} \end{aligned}$$

7. System Protection

7.1 Introduction

7.1.1 Purpose

The auxiliary system of a generating station provides the electric power necessary for station operation. To assure reliability and personnel safety, and to minimize damage to equipment during fault or other abnormal conditions, a properly designed protective system is needed. The primary function of the protective system is to remove from service any component of the auxiliary system that has malfunctioned. Malfunctions include faults, excessive overloads, overvoltages, undervoltages, and other conditions that may become hazardous, cause damage, or otherwise interfere with the operation of the system. A secondary function of the protective system is to provide an indication of the location and type of failure.

There are a number of ways to provide adequate protection for different types of equipment and systems. This section presents some basic protection methods that should be supplemented by operating experience and the bibliographic references listed at the end of the chapter.

7.1.2 Plant Operating Characteristics

The characteristics of the protective system should be coordinated with the operating characteristics and configuration of the generating unit and its auxiliaries. All stations, whether they be nuclear, coal, oil, gas, hydro, or cogeneration, contain unit generators. Each unit generator includes a turbine generator set, the auxiliary equipment required for the system, and an auxiliary power system. Failure of any of the major equipment, such as the turbine, will cause a complete shutdown of the unit. However, the failure of auxiliary equipment may not have the same result. Steam generating units typically have multiple boiler feed pumps, induced draft fans, mills, coal crushers, reactor coolant pumps, or other auxiliaries. These multiple auxiliaries are normally supplied from separate service buses to minimize the effects of a fault or failed component. When auxiliary equipment fails and is isolated, the backup piece of equipment will generally support the operation of the unit.

7.1.3 Design Features

System protection and coordination is needed to minimize damage to the system and its components and to limit the extent and duration of service interruption to only the affected part of the system. Economic considerations and the choice of system components will determine the degree of system protection and the level of coordination. Protection should be sufficient to satisfy at least the minimum system safety and reliability requirements. Modifying an inadequate system to obtain greater safety and reliability may prove more expensive and, in most cases, less satisfactory than designing these features into the original system.

A protective system should have the capability to

- 1) Isolate the affected portion of the service system without interrupting service of unit auxiliaries. This isolation should be as rapid as possible to minimize damage to components and the effect on the rest of the service system.
- 2) Operate only under those conditions for which protection is needed and remain either passive or biased against operation for all other conditions.
- 3) Reduce the duration of available short-circuit current to minimize potential damage to the service system and its components.
- 4) Limit the duration of undervoltage transients due to faults in the service system and prevent the unnecessary loss of equipment operation.
- 5) Utilize alternate circuits, automatic throwovers (or transfers), and automatic reclosing devices (where applicable) to minimize the duration and extent of equipment outages.

- 6) Provide primary and backup protection to ensure that a single component or relay failure will not prevent the isolation or clearing of a fault in the service system.

7.1.4 Planning a Protective System

The first step in planning a protective system is to draw an accurate single-line diagram of the power system. Next, the required relaying and metering circuits, including current and voltage transformers, should be added to the single-line diagram. Normally, the single-line diagram and relaying design should be worked on together to optimize the design. The relaying design will normally include both primary and backup protection. To make the single-line diagrams, the designer of the electric power system should first determine the load requirements, including the sizes and types of load, the location of principal loads, and special requirements. The method of system grounding should also be determined. The designer should also determine the available short-circuit current from the supply system at the point of delivery and the time-versus-current curves of the nearest supply system protection device.

Once a single-line diagram is completed, the system design philosophy is determined, and the relays are added, a preliminary coordination curve is developed for all loads and breakers. Upon receipt of the final vendor information on equipment, circuit breakers, and relays, a final check of these coordination curves is performed to verify the proper operation of the protective system. Relay setting information is then completed and distributed to the relay calibrators to set up the system relaying before operation. The coordination and protection design will be of no use if this field work is not properly planned and executed. The follow-up consists of proper installation, including testing and calibration of all protective devices, proper operation of the system and its components, and a proper preventive maintenance program, including periodic retesting and recalibration of all protective devices.

7.2 System Arrangement

Relaying systems for a service system really consist of small systems within themselves. Properly speaking, the protective relaying system includes circuit breakers, fuses, and instrument transformers as well as relays. In the medium and high-voltage areas, relays and circuit breakers generally function together. There is little or no value in applying one without the other. Medium and high-voltage circuit breakers require relays to initiate protective action. Most low voltage protection is supplied by circuit breakers and/or fuses that have both overcurrent sensing and interrupting capabilities.

Relays are not required to initiate protective actions during normal power system operation. However, should intolerable system conditions arise, they must be available to prevent serious outages and damage. Therefore, relays may operate infrequently (or never), even though they are connected to a system in a standby or monitoring mode for many years. In practice, the relays operate more often during test and maintenance than in response to adverse service conditions.

A relaying system should be able to respond to the large number of abnormalities that can possibly occur in a power system. Since it is simply not feasible to design a protective relaying system capable of handling all potential problems, the relay engineer must make compromises. In most cases, only those problems that are likely to occur according to past experience receive primary consideration. Naturally, this makes relaying somewhat of an art because there is judgement used in making selections. Different relay engineers will, using sound logic, design significantly different protective systems for essentially identical auxiliary power systems. Not only may the type of relaying system vary, but so may the extent of protective coverage. Too much protection is almost as bad as too little, if the additional relaying causes unnecessary tripping.

7.2.1 Basic Relaying Features

In the application of protective relays to the auxiliary electrical systems, the power system is divided into several zones, each requiring its own group of relays. The five design items listed below are important considerations in achieving a well designed and efficient protective system or zone.

- 1) *Reliability*. Reliability, as applied to protective relay systems, refers to the ability of the relay system to perform as intended by design. Incorrect or unnecessary operation is avoided.
- 2) *Speed*. Speed refers to how fast the relay system can detect an abnormal condition and initiate protective action such as fault detection and clearing.
- 3) *Selectivity*. Maximum service continuity with minimum system disconnection.
- 4) *Economics*. Ensuring that an electrical auxiliary system is well protected while minimizing cost.
- 5) *Simplicity*. A relay system should be designed with simplicity in mind, minimizing the number of components and the amount of circuitry involved.

It is not practical to satisfy fully all these design features simultaneously. Compromises should be evaluated on the basis of comparative risks/benefits.

Reliability consists of two elements: dependability and security. Dependability relates to the degree of certainty that a relay or relay system will operate correctly in response to system trouble. Security relates to the degree of certainty that a relay or relay system will not operate incorrectly. These two elements of reliability tend to counter one another. Increasing one element tends to decrease the other. Generally, a reasonable compromise between dependability and security can be achieved using relaying devices available today, resulting in highly reliable relay systems.

Speed is of primary importance in relay operation. Faster relay operation results in less damage to the equipment. Slower relay operation, with use of a time delay, results in more equipment damage but higher selectivity. Relays that can anticipate a fault would be the best, but, even if available, would undoubtedly raise the question of whether the fault or abnormal condition really needed a trip. The application of faster relays should also be measured against the increased probability of more unwanted or unexplained operations due to harmless transients. Time is the best method of distinguishing real and apparent trouble. Applied to a relay, high speed indicates that the operating time usually does not exceed 50 ms. The term instantaneous indicates that no delay is intentionally introduced in the operation. In actual practice, the terms high speed and instantaneous are frequently used interchangeably.

Simplicity in a protective relaying system is always desirable. However, the simplest relay system may not be the best and most economical. When other factors are equal, a simpler design will improve system reliability because there are fewer components that can malfunction.

Relay performance is generally classed as correct, no conclusion, or incorrect. Incorrect operation may be either a failure to trip or false tripping. The cause of incorrect operation may be poor application, incorrect setting, personnel error, or equipment malfunction. Equipment that can cause an incorrect operation includes defective relays, current transformers, voltage transformers, breakers, cable and wiring, relaying channels, or station batteries. Incorrect tripping of circuit breakers not associated with the troubled area is often as disastrous as the failure to trip. Hence, special care should be taken in both application and installation to ensure against the possibility of incorrect tripping. "No conclusion" is the last result in which no evidence is available to substantiate correct or incorrect operation.

7.2.2 Zones of Protection and Coordination

The normal approach used in relay applications is to divide the electrical auxiliary system into zones that can be protected while minimizing the amount of equipment disconnected. The electrical system is divided into protective zones for generators, transformers, buses, auxiliary circuits, and motors. Each zone is normally provided with primary and backup protection, and is coordinated with other zones to minimize the area deenergized during the fault. An auxiliary power system and its different zones for protection for transformers, switchgear, unit substations, and motors is shown in Fig 7.1. The purpose of the primary protective system is to provide the first line of protection within the guidelines outlined in this section. Since failures do occur, some form of back-up protection is provided to trip out the adjacent breaker zones surrounding the troubled area. Protection in each zone is overlapped, where practical, to avoid the possibility of unprotected areas. This overlap is accompanied by connecting the relays to current transformers, as shown in Fig 7.2. Relay coordination is accomplished by setting the relays so that the primary protection will trip before the backup protection. An example of the coordination of a motor on a bus is shown in Fig 7.3. Note that the primary protection is provided by relay 1 and the backup protection by relays 2 and 3. These relays will allow the

motor to start without tripping and interrupt a fault before the motor or its feeder cable is damaged. The relays also protect the cables feeding the motor and bus.

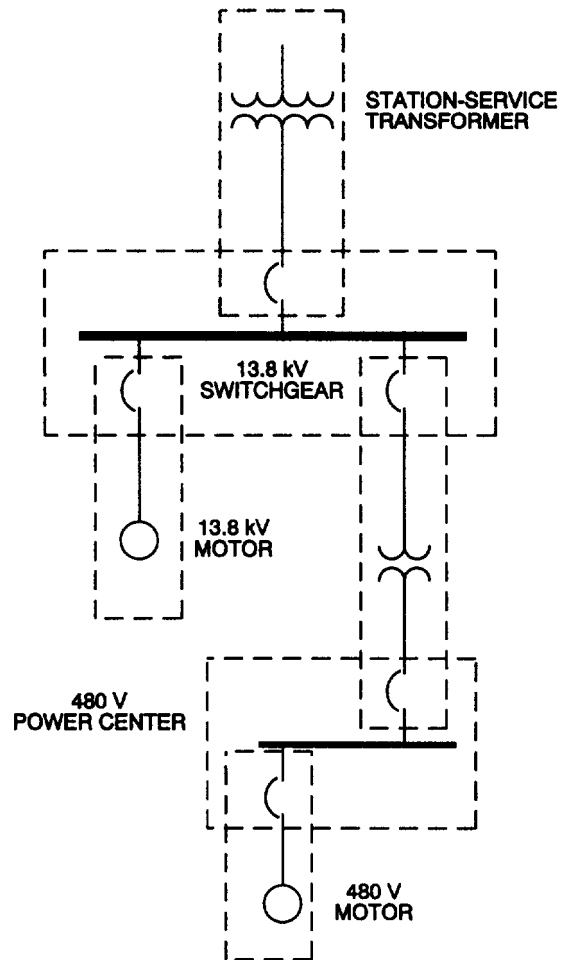


Figure 7.1 — Typical Zones of Protection

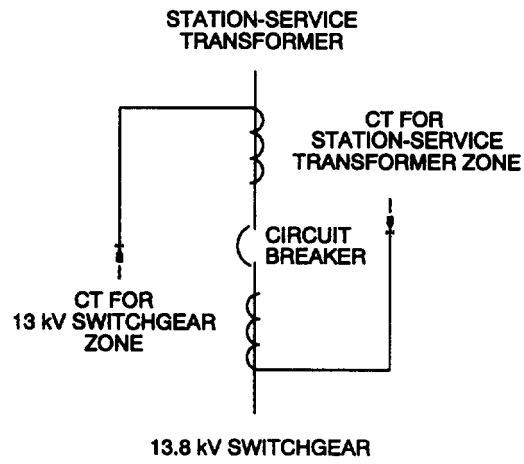


Figure 7.2 — Overlapping Protection Around a Circuit Breaker

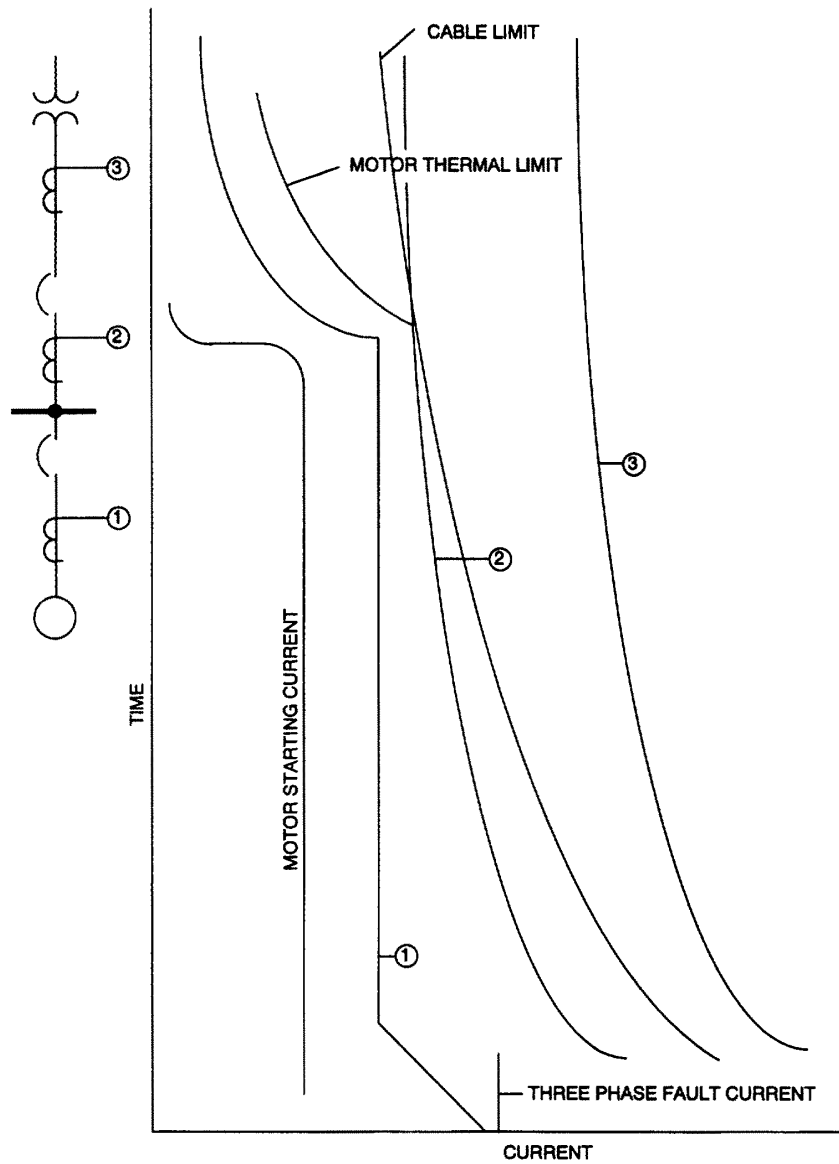


Figure 7.3 — Typical Motor Coordination

7.3 Types and Characteristics of Protective Devices

7.3.1 General

The various types of protective devices, such as fuses, medium and high-voltage circuit breakers and relays, and low-voltage circuit breakers, have different protective characteristics. Protective characteristics are inherent in the design of fuses (see Fig 7.4). A fuse protects a circuit by fusing open a current responsive element when an overcurrent or short-circuit current passes through it. A fuse combines both the sensing and interrupting element, in one self-contained device and is thus self-interrupting. A fuse is direct acting because it responds only to a combination of magnitude and duration of circuit current flowing through it. A fuse is a single-phase device and normally does not provide a means either to manually or automatically open or close the electrical circuit. Each fuse has its own specific time current characteristic.

Low-voltage circuit breakers (600 V and below) are normally supplied with internal protective trip devices and are thus self-interrupting (see Fig 7.5). Protective characteristics may be fixed (not adjustable) or adjustable.

Two types of low-voltage circuit breakers are generally available: molded-case circuit breakers and low-voltage power circuit breakers. A molded-case circuit breaker is assembled as an integral unit having a trip characteristic range and means of making or interrupting the energized circuit. The low-voltage power circuit breaker, often known as the “air circuit breaker,” obtains its trip characteristics from interchangeable trip elements, solid-state devices in modern equipment or electromechanical in older equipment, and has a trip/close control circuit to make or break an energized circuit. The solid-state elements use diodes, transistors, resistors, capacitors, and other low power semiconductor components in logic combinations to provide various trip characteristics.

Medium and high-voltage circuit breakers, on the other hand, do not include built-in (or self-contained) sensors and require protective relays with inputs from instrument transformers to sense a fault (see Fig 7.6). These breakers have ac or dc control circuits to initiate opening or closing the breaker. The control circuit is operated by trip/close circuits or relays.

Different relays provide various operating characteristics. The use of a fuse or circuit breaker depends upon the type of equipment to be protected and the characteristics of the power system involved. In the power industry, circuit breakers are usually chosen due to fuse replacement and single-phasing problems involved with fuses, unless the interrupting rating and/or coordination becomes a problem. Protective devices are available with combinations of three basic operating characteristics:

- 1) *Instantaneous Characteristic.* A protective characteristic that gives instantaneous operation when the input quantity falls within the operating region. An instantaneous relay is a relay that has no delay purposely introduced in its action. An example is an instantaneous overcurrent relay that operates with no initial time delay when current exceeds the operation setpoint. For coordination and selectivity, a time delay must, be added.
- 2) *Inverse Time Characteristic.* A characteristic in which the input quantity and operating time are inversely related throughout a substantial portion of the performance range. An example is an inverse time overcurrent relay. The higher the current, the faster the relay operates.

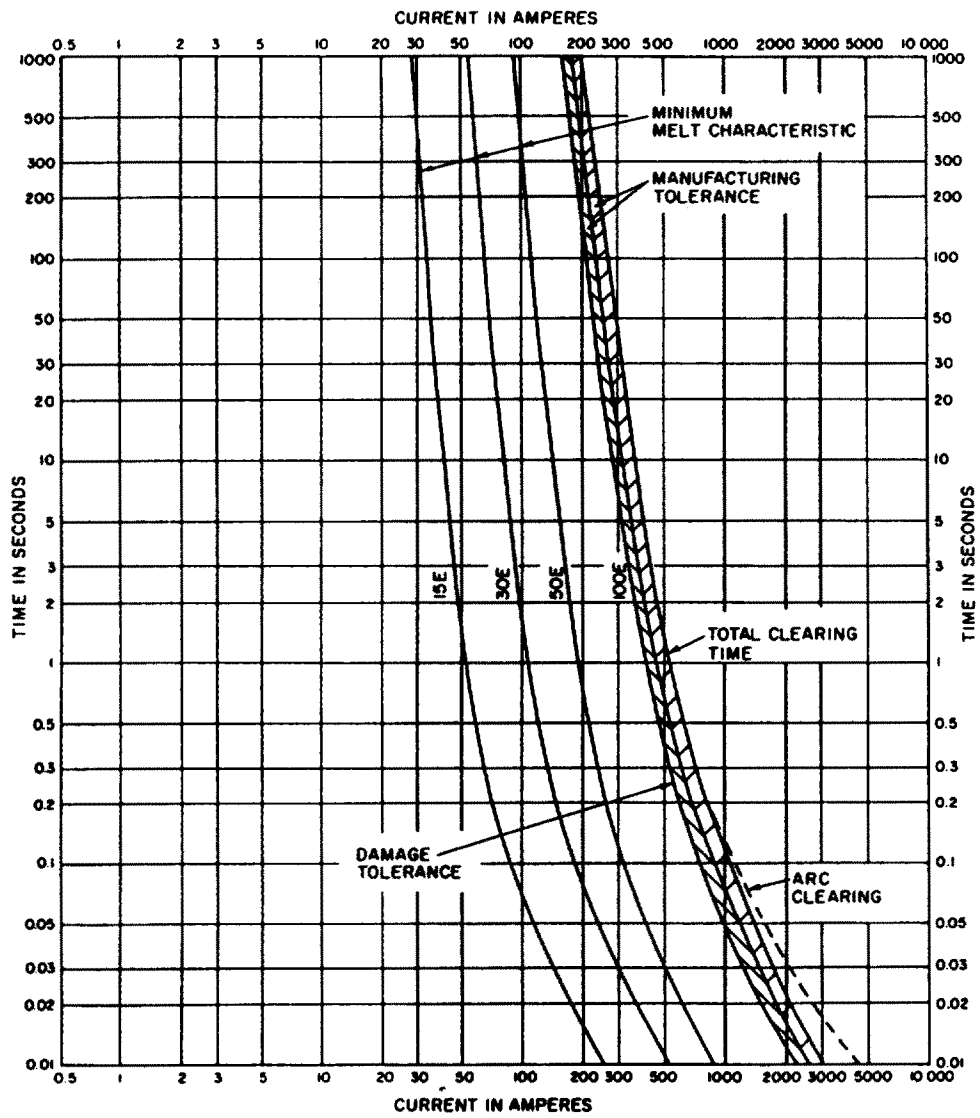
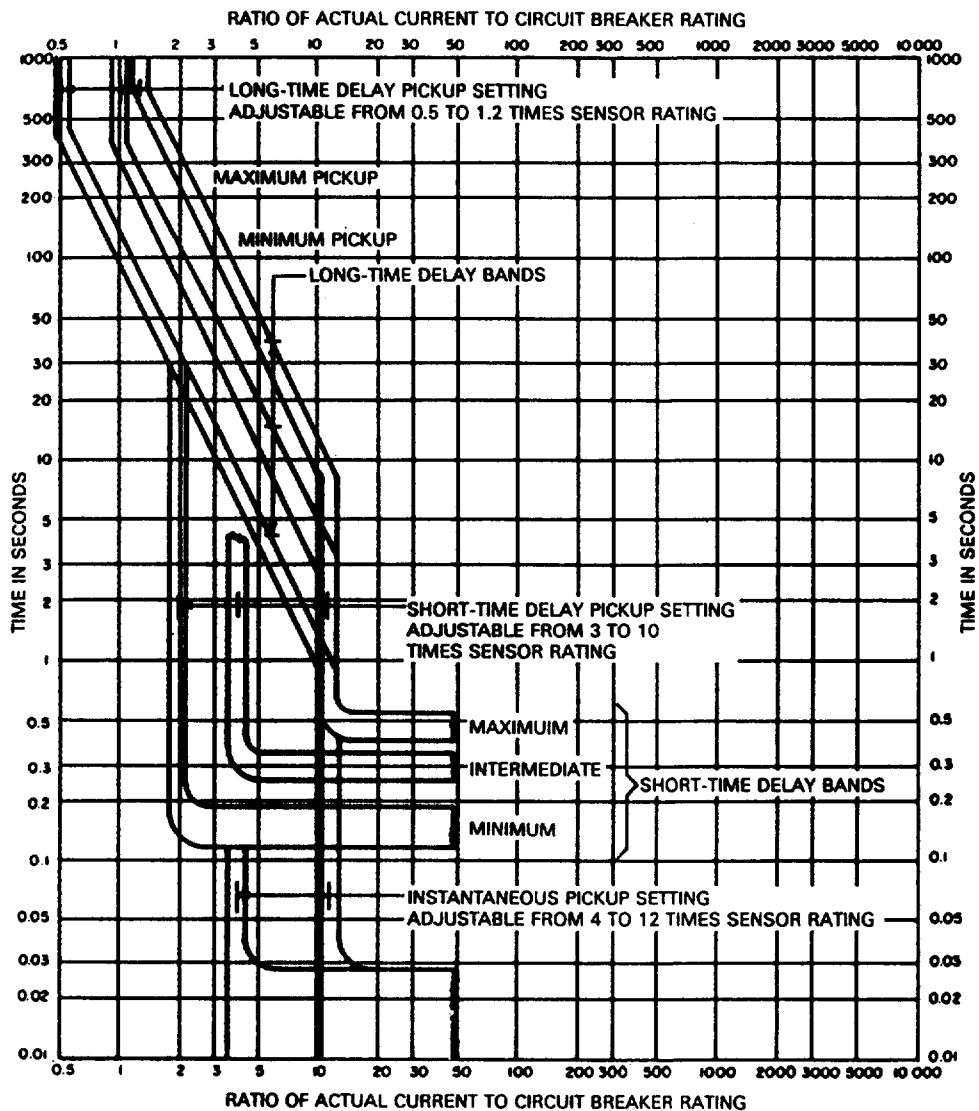


Figure 7.4 – Typical Time Curve



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Figure 7.5 – Adjustability Limits of Low-Voltage Power Circuit Breaker Trip Devices

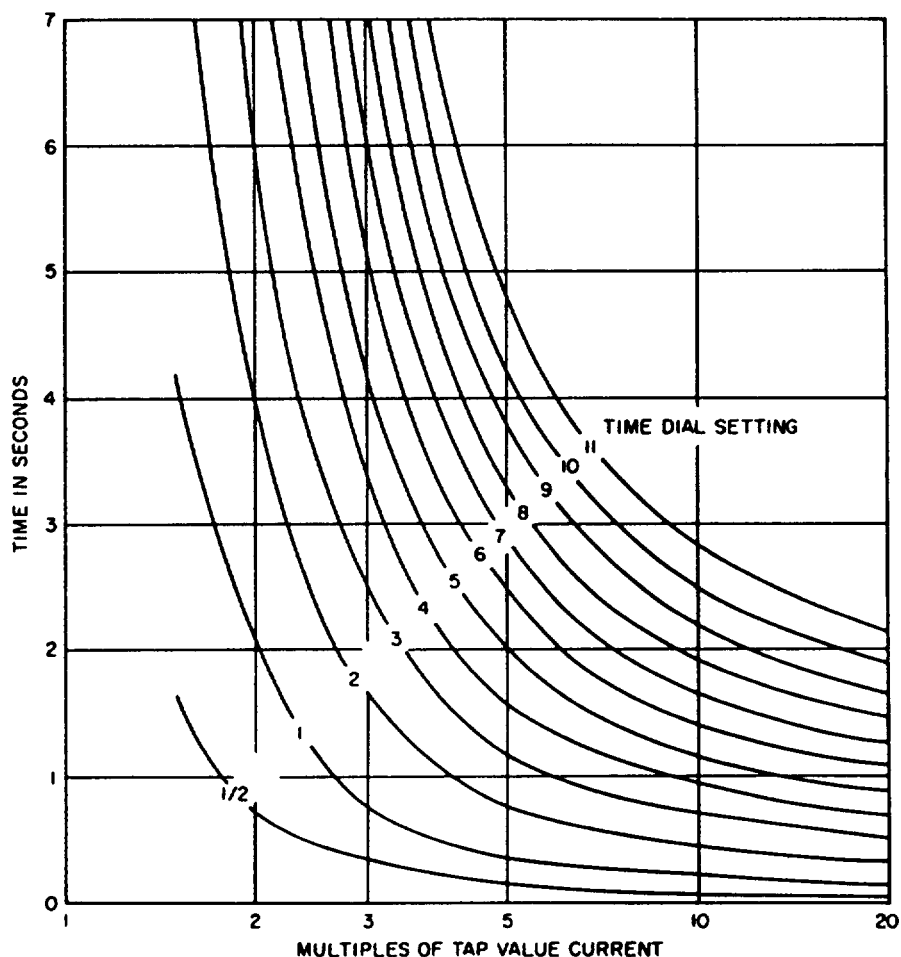


Figure 7.6 — Typical Relay Curve

- 3) *Thermal Characteristic.* A thermal characteristic is an approximate replica of the heating of the equipment being protected. Current flowing to the device is used to develop the replica of the heating of the protected equipment. Operating time is inversely related to current.

There are two basic physical types of relays: solid state and electromechanical. The solid-state relays operate statically similar to the relay elements described above. For example, once a certain set of time-current conditions have been met, the relay will operate (i.e., conduct) to energize a trip/close circuit. Electromechanical relays operate with a plunger being drawn into a solenoid, or with a torque developed on a rotating induction element in a stationary electromagnetic coil. On electromechanical relays, the mechanical movement of the relay operating mechanism is imparted to the contact structure to open or close the relay contacts. Most electromechanical relays have a control spring or are restrained by gravity so that they assume a given position when completely deenergized. A contact that is closed under this condition is called a “normally closed” or “b” contact. A contact that is open is called a “normally open” or “a” contact.

When a relay operates, it opens its normally-closed contacts and closes its normally-open contacts. The smallest value of actuating quantity (current, voltage, or a combination thereof) that will cause such an operation as the quantity increases is called the “pickup” value. The actuating quantity at which the relay resets its contacts as the quantity is decreased from above the pickup value is called the “reset” or “dropout” value of the relay. Adjustment of the pickup or dropout values may be provided electrically by tapped current coils or by tapped auxiliary voltage transformers or

resistors. Adjustment may also be provided mechanically by adjustable spring tension or by varying the initial air gap of the operating element with respect to its solenoid or electromagnet.

7.3.2 Overcurrent Protection Relays

The overcurrent protection relays are the relays most commonly used for short circuit or overload protection. Various combinations of instantaneous, long-time, short-time, and thermal elements are available depending on the power system application. For high-voltage applications, instantaneous and inverse time relays are normally used, and for low-voltage applications, instantaneous and thermal elements are normally used.

The simplest overcurrent relay is the solenoid or solid-state type that provides instantaneous overcurrent protection. Instantaneous relays are usually set to operate at current values above the normally expected transient levels but below the fault current levels. Inverse or thermal characteristics are added to provide inverse time overcurrent protection for lower magnitude short circuits and overcurrents within the range of transient occurrences. Various inverse time characteristics are available to fit the requirements of particular applications. Whether the relay is solid state or electromechanical, the instantaneous, inverse time, and thermal characteristics can be changed by adjustments or interchanging parts.

7.3.3 Overcurrent Relays With Voltage Restraint or Voltage Control

A short-circuit fault on an electric system is usually accompanied by a large voltage drop, whereas an overload causes only a moderate voltage drop. Therefore, a voltage restraint or a voltage controlled overcurrent relay is able to distinguish between an overload and a fault condition. The electromagnetic voltage restraint overcurrent relay is subject to two opposing torques, an operating torque due to the current and a restraining torque due to the voltage. The electromagnetic voltage controlled overcurrent relay operates on the overcurrent when permitted by a voltage relay that is set to operate at some predetermined value of voltage. Such relays are useful when it is desirable to be able to set the overcurrent characteristic of the relay close to the load current and still be sure that it will not operate incorrectly on an overload current.

7.3.4 Ground Relays

When the auxiliary system neutral is grounded, ground fault current can flow in the conductors and a ground relay may be used to detect the faulted components. A ground relay is ordinarily an overcurrent relay connected in the neutral ground lead of the power system, or, in current transformer circuits, sensing zero sequence currents. It can be set to pick up at much lower current values than the phase relays because it detects zero sequence currents and is not affected by positive or negative currents. Overcurrent relays used for ground protection are usually the same type as those in phase leads, except that a more sensitive range of minimum operating values may be needed.

When the auxiliary system is ungrounded, substantial ground fault current cannot flow in the conductors during abnormal conditions. In this case, a combination of voltage transformer connected wye-broken delta, a resistor, and voltage relay is used to measure the resultant zero sequence voltage in the system that; indicates the presence of ground. This relay usually operates an alarm to indicate a ground on the system because it is difficult to provide selective protection of an ungrounded system, and time is available before equipment is damaged to manually clear the fault.

Doughnut type current transformers are current transformers wound on a toroidal core. When the three-phase conductors are passed through the center of the core, the current transformer secondary current is proportional to the zero sequence current. The current transformer only has a secondary current flow during ground faults. Doughnut type ground-sensing current transformers with low ratios are widely used for sensitive ground protection on large motors, where inrush can saturate current transformers and produce false residual currents, and on systems that permit a low value of ground-fault current.

7.3.5 Directional Relays

A directional overcurrent relay utilizes an overcurrent element that is controlled or supervised by a directional element. In the directional element, the phase angle of a current is compared to the phase angle of a voltage or another current in that unit.

The reference current or voltage is called the polarizing current or voltage. The relay operates only for current flow in one direction and will be insensitive to current flow in the opposite direction. Directionally controlled overcurrent relay current elements are inactive until the directional element detects current in the tripping direction and releases or activates the overcurrent unit.

7.3.6 Voltage Relays

A voltage relay is one that functions at a predetermined value of voltage. It may be an under or overvoltage relay or combination of both. In general, it is a plunger, induction, or solid-state type relay. Each type is provided with different settings to permit the voltage pickup or dropout to be adjusted. The plunger type relays are usually instantaneous in operation, although they can be furnished with bellows, dashpots, or other delay devices. The induction and static type of relays are normally equipped with adjustable time delays.

The time delay has an inverse characteristic. That is, its operating speed increases with the deviation of voltage from the setting of the relay at which it will operate. Voltage relays are sometimes needed to be inoperative during transient voltage disturbances. For this purpose longtime delay relays are available.

7.3.7 Differential Current Relays

A differential relay operates by comparing currents at two or more locations on a power circuit. A fault between the locations will cause a change in the relative values of the currents, resulting in a differential current. This current is used to operate the relay. The simplest form of differential current protection for transformers, generators, or motors is an overcurrent relay connected to measure the difference of current value as obtained from current transformers on opposite sides of transformers or in the two ends of each phase of the machine winding. The percentage differential relay requires that the two compared current values be a certain percentage different from one another before the relay will operate. These relays permit a more sensitive setting without risking false operation due to small differences in the current output from current transformers. Available differential percentage characteristics range from 10% to 50%. Most differential relays are essentially instantaneous in operation. To avoid operation from the inrush of magnetizing current when energizing transformers, various relay desensitizing schemes are used. Inrush current to a transformer may contain harmonic current components not found during normal operation. A harmonic restraint type relay can distinguish between magnetizing inrush and internal fault current.

7.3.8 Pressure and Gas-Sensing Relays

Transformers that are filled with oil for insulating and cooling can be protected with sudden-pressure or gas sensing relays. When a fault occurs in the equipment, the resulting overheating and arcing produces a gas in the oil. The gas can be directly or indirectly detected as a high rate of pressure rise by one of these relays.

7.3.9 Fuses

Fuses are devices for isolating faults and limiting available fault current on power feeders and, for this reason, are applied to many station service system feeders. However, fuses have certain disadvantages. These disadvantages include the following:

- 1) Fuses are current devices only and cannot be used when voltage restraints are needed.
- 2) Fuses must be manually replaced before the circuit can be reenergized (except for distribution system repeater fuses).

- 3) Fuses are limited in maximum circuit capacity (i.e., fuses are not usually available for motors greater than 5000 hp at 6900 V).
- 4) When applied to three-phase circuits, they require additional protective devices to prevent single-phase operation. Present designs provide indication or control contacts on fuses that will indicate a blown fuse.

Use of fuses usually improves the reliability and selectivity of the protection system. When a radial feeder supplies a single motor or load, manual replacement of fuses is not detrimental because the circuit should be repaired before it can be reenergized.

When fuses are applied with motor starters, the starters may be latched or electrically held. In these applications, additional relays may be used to provide a complete protection system. Manufacturers generally publish two sets of curves for fuses: minimum melting time and minimum clearing time. When applying fuses for circuit protection, the engineer should remember to consider the clearing time of the fuse as opposed to its melting time. After the fuse element melts, there is an arc present for a certain amount of time that must extinguish before the fault is cleared.

7.4 Principles of Relay Applications

7.4.1 General

To successfully apply protective relays, the protection problem should be accurately and completely defined. Although the development of a concise statement of the problem can be difficult, the time spent will prevent improper relay operation and subsequent corrective measures. Information should be gathered on the following areas:

- 1) Impedances and system configuration including possible future expansion
- 2) Maximum and minimum load information and fault studies including transient overloads and voltage drop due to motor starting and energizing feeders
- 3) Voltage and current transformer locations, connections, and saturation/operation characteristics
- 4) Degree or extent of protection needed
- 6) Existing procedures and operation practices
- 7) Fault and overload capabilities of equipment

The system would be represented by a single-line diagram showing, in some detail, the bus arrangement and interconnections, locations of the circuit breakers and fuses, the connection of power transformers, the location and connection of instrument transformers, cable sizes, and the ratings and winding ratios of all equipment. The transformer connections and system grounding are particularly important. The type and location of ground sources should be kept for application of ground relays.

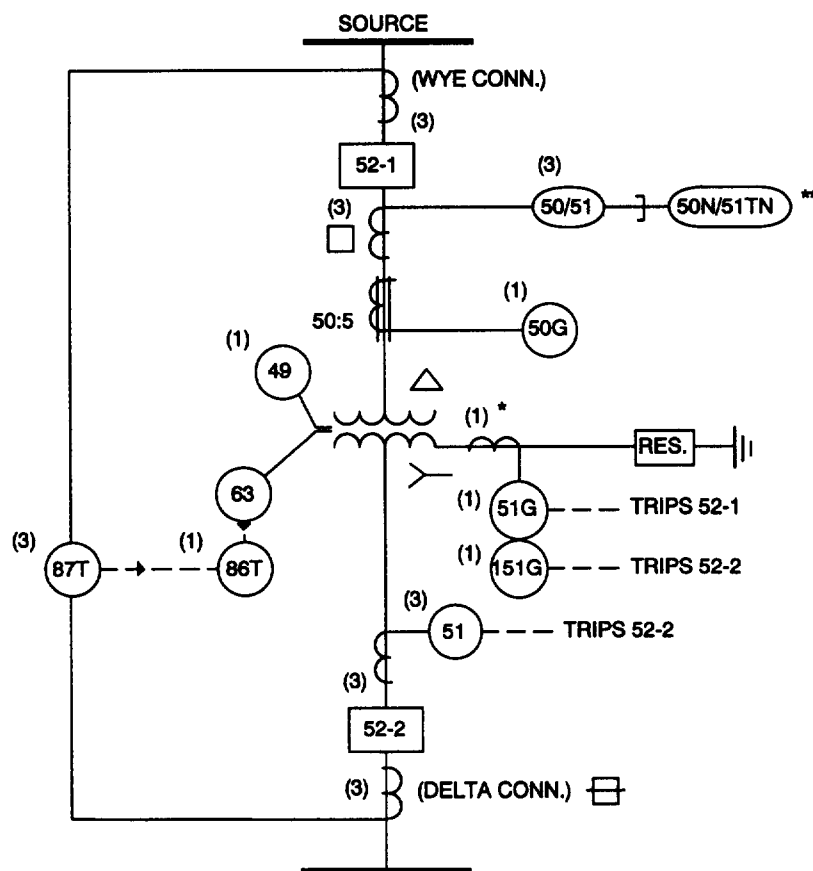
Once the system configuration and the protection requirements are known, the relaying engineer can select the proper relays, fuses, and circuit breakers for the different types of equipment. The following sections will look at each of the major types of equipment and discuss the considerations for the protection of this equipment in a generating station.

7.4.2 Transformer Protection

Even though a transformer is one of the most reliable components in the auxiliary system, proper transformer protection is required to prevent excessive damage, personal injury, and unnecessary outage time during the unlikely event of a fault condition. This section will discuss the protection of the three basic transformer types typically found in a power station service system. The major transformers are the unit service transformers and the station service transformers, which normally range from 5–80 MVA. These transformers supply the medium voltage buses that feed major plant auxiliaries above 250 or 300 hp and the low-voltage substations. Typical transformer protection devices and their applications on a large transformer are shown in Table 7.1 and Fig 7.7.

Table 7.1 – Transformer Protection Devices

ANSI Device Number	Function	Suggested Settings and Remarks
49	Thermal Overload	Factory Set
50G	Ground Fault	Set at minimum pickup
50N/51N	Ground Fault Residual	The residual ground fault relaying should be set as low as practical considering phase CT mismatch. The relay setting should be coordinated with the available ground fault current and should not be set above 10% of the available ground fault current.
50/51	Phase Fault	Set device 50 so that it does not operate for thru-faults or magnetizing inrush. Set device 51 at 150–250% of transformer rating.
51	Phase Fault	Set to coordinate with downstream devices, with maximum pick up of 250% of self-cooled rating of transformer.
51G 151G	Ground Fault	Set at 0.5 A tap and use time dial to coordinate with downstream devices and each other. (51G Longest)
63	Transformer Internal Fault	Gas accumulation and gas pressure relays can be adjusted. See manufacturer's recommendations.
86B	Lockout	No setting. Must trip all breakers on bus section.
86T	Lockout	No setting. Must trip all breakers to isolate the transformer.
87T	Differential Phase and Ground Faults	Set taps to correct for CT ratios.



□ = CT RATING SHOULD BE ~200% OF TRANSFORMER SELF-COOLED RATING

▣ = CT RATING SHOULD BE ~350% OF TRANSFORMER SELF-COOLED RATING

** = 50/51N IS ALTERNATE TO 50G.

* = CT RATING SHOULD BE 50% OF MAXIMUM RESISTOR CURRENT RATING

Figure 7.7 – Typical Large Transformer Protection

The next size, the 480 V substation transformers, are usually dry-type, 500-2500 kVA, and are used to feed precipitators and auxiliaries smaller than approximately 250 hp and motor control center buses. The smallest size, the 240/120 V distribution transformers, are used to feed the smallest auxiliaries, 1 hp and below, and buses.

The type of protection selected for a transformer will vary according to the size and connection; however, it usually includes

- 1) The detection and indication of conditions occurring within the transformer that may cause damage or failure
- 2) The protection of the electric system from the effects of a transformer failure
- 3) The protection of the transformer against system overloads and faults
- 4) The protection against through faults that have failed to clear

A failure of a transformer can be caused by a number of internal or external conditions. Other than physical or environmental problems, the most common transformer problem is winding failure. The insulation deterioration, overheating, mechanical stress, vibration, or voltage surges causing these failures generally result from one of the following conditions:

- 1) Overloads
- 2) Short circuits
- 3) Overvoltages (steady state and transient)
- 4) Cooling system failures

Protection against these conditions is achieved by the proper combination of sensing devices, relays, and circuit interruption devices, which detect the condition and sound an alarm or disconnect the transformer from the system. The sensing devices should be able to distinguish between the various normal operating conditions and the abnormal conditions.

An overload will cause a rise in the temperature of the transformer winding, its oil (if the transformer is oil cooled), and the related components. If the final temperature is above the design temperature limits, some deterioration of the insulation and oil will occur, thereby reducing the useful life of the transformer.

Insulation may be weakened such that a moderate overvoltage might cause insulation breakdowns before the expiration of the expected service life.

The prevention of an overload is primarily a design problem. The transformers should be sized to handle all normally and abnormally operating secondary loads. Protection against overloads consists of load limitations, overload detection, and hot spot temperature relays. In a generating station service system, transformers are generally designed to have sufficient capacity to supply the maximum expected load for all operating conditions. In addition, a capacity margin is provided for future load growth. However, in some instances such as a reserve service system, the transformer may be designed to carry a load smaller than the plant auxiliary load. Under this condition, when a load bus is transferred to the reserve service system, sufficient load should be shed so as not to exceed the rating of the transformer supplying the medium-voltage buses.

Overload conditions can be detected by using overcurrent relays. Monitoring devices mounted directly on the transformer are also available as standard or optional accessories. These devices include liquid temperature indicators, winding temperature relays, and hot spot temperature equipment, and are normally used to initiate alarms.

In addition to thermal damage from prolonged overloads, transformers are adversely affected by internal or external circuit fault conditions. Both internal and external faults should be disconnected (isolated) as rapidly as possible to reduce damage. The speed of protective relays may be limited by the selective coordination requirements of the system being supplied by the transformer. There are several sensing devices available that provide varying degrees of short-circuit detection. These devices detect two different aspects of fault effects. The first group of devices senses the formation of gases caused by an internal fault. These gas sensing devices include a pressure-relief device, sudden-pressure relay, gas detector, and combustible gas relays that may be used to sound an alarm or to disconnect the transformer. Generally, on generating station transformers, only the sudden-pressure relay is used for tripping the isolating circuit breakers. Other gas detection devices are used for alarm only.

The second group senses the short-circuit current directly. These include overcurrent relays, fuses, and differential relays.

Fuses and/or overcurrent relays are applied to provide back-up protection, i.e., their operation is delayed to permit the system branch protection to isolate faults on those circuits while maintaining service to the rest of the system. Differential relays provide instantaneous detection and tripping of isolating circuit breakers for internal transformer faults. All transformer relays should be set or restrained from operating on magnetizing inrush current usually 8-12 times full load current for 0.1 s.

Sudden-pressure relays or differential protection are usually not provided for 480 V substation transformers. The transformers often are ventilated dry or gas-filled transformers. These transformers are protected by phase and neutral overcurrent relays and are sometimes provided with winding-temperature relays for alarm purposes and for controlling cooling fans.

The unit and station service transformers normally have sudden-pressure relays and differential protection. In many instances, phase and neutral overcurrent relays are also provided for backup protection. When the unit service transformer and generator step-up power transformers are connected to the generator terminals, an overall unit differential relay is often provided for backup protection of the equipment. This relay zone includes the neutral side of the generator and the high-voltage side of the unit service and generator step-up and power transformers. Frequently, this zone is extended to include the generator high-voltage circuit breaker(s). A fault occurring anywhere in this zone requires immediate shutdown of the unit. Protection against 60 Hz overvoltages is provided by volts/hertz relaying.

Distribution transformers are normally provided with overload and fault protection with fuses or molded-case circuit breakers that sense overcurrent.

7.4.3 Motor Protection

Electrical hazards to induction and synchronous motors found in power stations are primarily the result of thermal and mechanical forces that cause deterioration. These forces, for the most part, degrade the mechanical and dielectric strength of the motor insulation so that voltages and mechanical stresses are more likely to produce problems including phase-to-ground, phase-to-phase, phase-to-phase-to-ground, three-phase, and turn-to-turn faults. Protective relaying for motors is provided to prevent motor mechanical and thermal degradation, to limit the equipment/personnel damage, and to minimize the effects on the power system upon occurrence of a fault.

The mechanical and thermal problems associated with excessive heating are usually caused by prolonged operation with a locked rotor, undervoltage, torque requirements beyond the motor rating, excessive repeated starts, unbalanced supply voltages, blocked ventilation, high ambient temperature, and pullout or loss of field for synchronous motors. This excessive heating, associated with the above listed abnormal conditions, can be detected for alarm and tripping purposes in various ways by monitoring actual temperature and/or currents within the motor.

Direct motor temperature measurement can be accomplished using resistance temperature detectors (RTDs) embedded between coils in the stator slots. An RTD may be made of any one of several metals including copper, nickel, and platinum, and is usually connected to a temperature relay for alarming at an abnormally high temperature and tripping at a damaging temperature. The RTD is located so that it is directly influenced by the winding temperature and the relay can be provided with a time delay to add a time lag during momentary rapid changes (i.e., motor starting). Because the RTD metal resistance varies in a precise and predictable manner with temperature, the RTD provides a discriminating way to sense stator temperature.

While the RTDs will eventually sense the overheating caused by the above listed operational problems, motor current (whether it be stator or rotor) provides a convenient and more timely method of detecting an over-heating problem. Stator current is an accurate indicator of load level. The degree of unbalance in phase currents or voltages (the presence of a negative sequence component) is indicative of voltage imbalance problems. The phase relation between motor current and voltages (i.e., motor power factor) provides a means to detect locked rotor, loss of field, or pullout of synchronous motors.

Under load conditions, induction motor rotor speed is reduced (by the amount of slip) and the rotor current and frequency are proportional to the load or slip. AC current also flows in the rotor during starting, during instability, and following load change. All of these effects are proportional to slip.

Power factor is also an indicator of motor overload or locked rotor, loss of field, or pullout in a synchronous motor. Motor impedance is dependent on slip (or rotor speed). During the starting period, the impedance and power factor remain relatively constant until significant rotor speed is attained (roughly half of the starting time has elapsed). At this speed, the impedance increases and the power factor angle begins to decrease significantly. It is important to note that

locked-rotor impedance is essentially independent of motor terminal voltage, whereas current varies directly with terminal voltage. A locked-rotor protection relay for large motors that uses impedance as the sensing quantity can be used to prevent prolonged locked-rotor conditions. Locked-rotor protection is often provided by use of a long-time inverse overcurrent relay. For situations in which an overcurrent relay and an impedance relay are not suitable, a time-delayed instantaneous relay is sometimes used. To apply locked-rotor protection properly, a thermal limit curve with starting current versus time is required from the manufacturer. Where coordination is tight, the curve should include hot and cold starting curves at two different voltages with the requisite thermal limit acceleration curves.

Relays are also available that use motor power factor to detect synchronous motor pull out and loss of field. For either case, the current into the motor goes more lagging (with respect to the voltage) initially for motor pull-out and continuously for loss of field. Since motor starting power factor is in the relay operating region, the relay should be blocked during this period, usually with an auxiliary contact on the field breaker. Phase voltage imbalance relays and power-factor relays are normally used to detect these problems in motors.

Insulation failure, resulting from the excessive mechanical forces and overheating mentioned above, may result in certain types of faults. Detection for these faults should be sensitive and quick to minimize motor damage and reduce the impact on generating station availability. Turn-to-turn faults within a given phase are very difficult to sense and, except in the extremely large motors in which elaborate protection is warranted, are allowed to evolve into one of the other types of more easily detected faults before being cleared. Phase current and/or phase-to-ground currents seem to be the best indicators of faults. Instantaneous overcurrent relays detect phase faults, and sensitive ground relays detect the abnormal presence of zero-sequence current during a ground fault. Where more protection is desired, or when the motor-starting current is close to the fault current, differential current relays can be used. These relays, which compare the current flowing into each motor winding with the current flowing out, provide a sensitive method of detecting phase faults even when the current level of the fault is below normal load current.

Undervoltage relays are also used to ensure that the proper voltage is available when energizing a motor upon transferring its voltage source to protect the motor from undervoltage thermal and mechanical stresses.

Table 7.2 lists the types of relay functions usually available for motor protection. Microprocessor based relays available today can provide many of the relay functions as well as other functions in a single relay. Fig 7.8 describes the protection needed for motors typically between 300 and 1500 hp. Fig 7.9 describes the more elaborate protection needed for motors typically larger than 1500 hp.

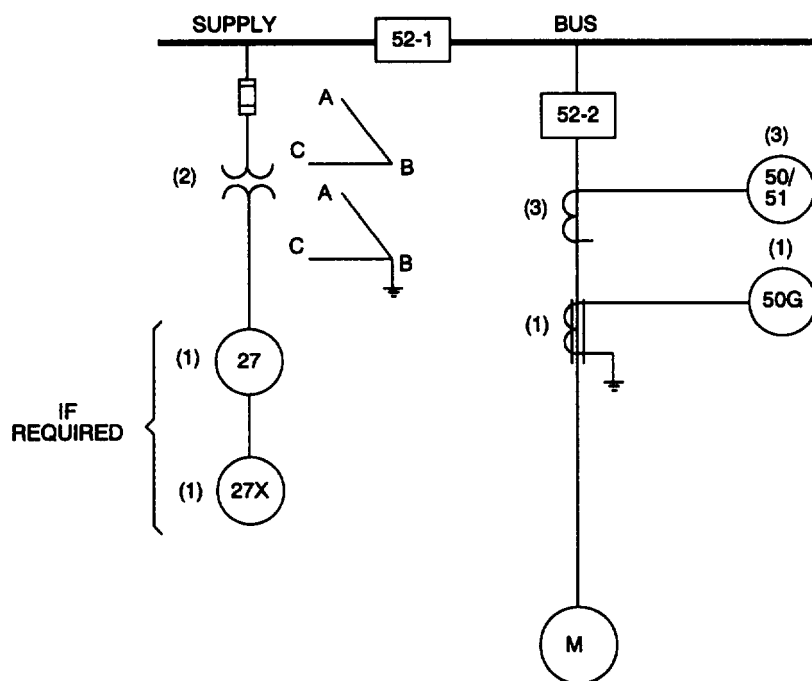
Motors less than 100 hp are typically protected with molded-case circuit breakers in combination with motor starters with overload relays.

Motors between 100 and 300 hp are typically 460 V and are protected with low-voltage circuit breakers with long-time and instantaneous trip characteristics.

Most motors above the 300 hp level are of higher voltages (2300 V or above) and are protected with circuit breakers and relays.

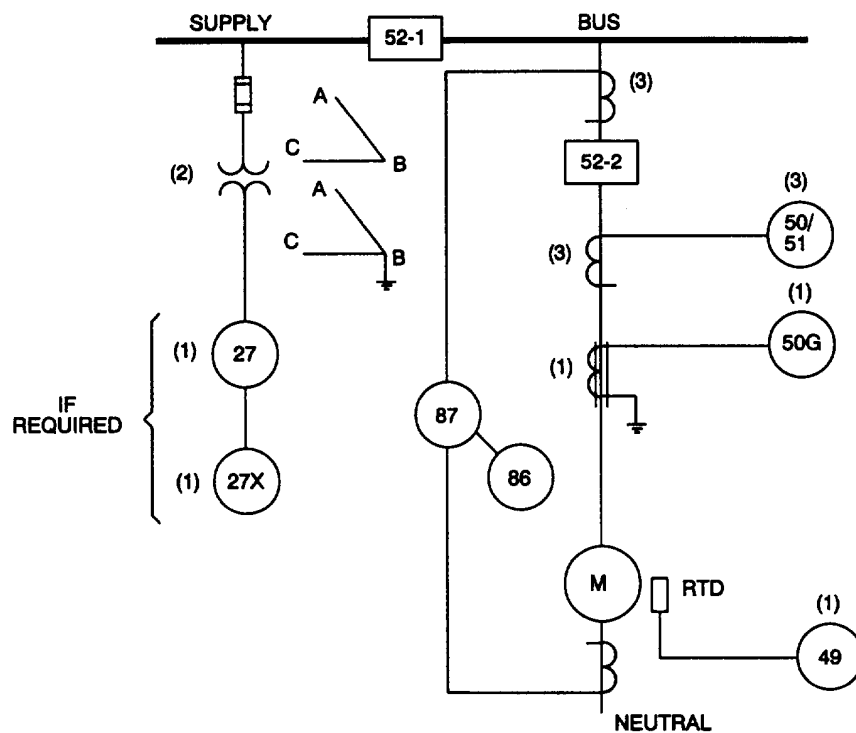
Table 7.2 — Motor Protection Devices

ANSI Device Number	Function	Suggested Settings and Remarks
27	Undervoltage	Set to override voltage drop due to motor starting. Set to 90% of system rated voltage to assure adequate steady state voltage.
27x	Auxiliary Contacts	No setting. Used on multimotor bus.
38	Bearing Temperature	Factory calibrated for desired temperature.
46	Current Unbalance	Set to pickup at .15 pu negative sequence current. The motor heating constant K should be assumed to be 40 and the tripping delay set accordingly.
49	Overtemperature	Set for motor safe operating temperature.
50	Phase Fault	Set at 200% of locked rotor current. Can be omitted when differential relay, device 87, is used. Maximum phase sensor. Set 115% of locked rotor.
50G	Ground Fault	Single unit. Use with 50:5 CT. Use relay with low setting range. Set at minimum pickup with 6 cycles delay.
51 (50/51)	Locked Rotor (may include phase fault)	Use when starting time is over 20 s and less than 70 s. Set at 105 to 200% of motor full load amperes. Set time dial to permit starting. (For 50, see above).
55/78	Pull-Out (synchronous motor only)	Set per relay and motor manufacturer recommendations.
81	Underfrequency	Used when automatic high speed reclosing is applied to source breakers. Set to trip before reclosing occurs.
86	Lockout	Auxiliary relay. No setting required.
87	Differential	Set for minimum pickup current if adjustment of pickup current is possible.



NOTE: PHASE CTs SHOULD BE ~150% OF FULL LOAD

Figure 7.8 – Typical Motor Protection Between 300 and 1500 hp



NOTE: PHASE CTs SHOULD BE ~150% OF FULL LOAD

Figure 7.9 – Typical Motor Protection 1500 hp and Above

On large motors, some form of differential relaying is needed to obtain high-speed fault detection, where its cost can be justified in the interest of sensitive phase relaying. The two types of differential relaying normally used on these motors are current difference and flux balancing. Current difference, as shown in Fig 7.9, uses overcurrent relays connected to respond to any difference between the current fed into the motor and the current fed from the motor supply bus. Note that this also provides protection for the cable feeding the motor. The flux balancing differential scheme, using a current relay, is generally applied at the motor terminals where space permits. Each phase current goes in and out of the toroidal current transformer producing flux cancellation. If the two currents are unequal, the net flux generates a voltage in a winding on the core, causing operation of the relay.

Loss of field relaying used in protecting medium and large generators can be applied to large synchronous motors. This type of loss of field relay is considered superior to the power-factor relay because the more confined trip area avoids some stable swing conditions that may be incorrectly sensed by the power-factor relay as loss of field. Time delay can prevent incorrect tripping and still provide adequate sensing of field loss by the power-factor relay. The so-called power-factor relay used for field loss and out-of-step detection is, and has been, a directional relay with a maximum torque (or sensitivity) angle like any other directional relay. This relay is connected to operate when the current goes lagging by approximately 30 or more. Neither the loss of field relay nor the power-factor relay can provide all-encompassing out of step protection. The loss of field relay is hampered by its restricted trip area, and the power-factor relay is hampered by its longer time delay requirement. The out of step notching relay is considered most effective for reliable detection of out of step conditions. It counts power reversals and, after the seventh reversal, initiates tripping.

A new concept presently under consideration for large motors, which should relieve the need for locked-rotor relays to differentiate between locked-rotor and acceptable starts, involves the use of a distance relay. Also, as a secondary function, the distance relay provides high-speed phase and ground fault detection. Overcurrent relays of the instantaneous or time delay types are difficult or impossible to apply in situations in which the permissible locked-rotor time is less than the motor starting time. Terminal voltage during starting can vary widely as system conditions change. Starting current and permissible locked-rotor time also change with system conditions.

Power factor is low initially, then increases, and then becomes low again during an unloaded start. Motor impedance, on the other hand, is fairly constant at zero speed irrespective of voltage level. Even with a fixed supply system and a predictable motor terminal voltage during starting, an instantaneous overcurrent relay with a 90% dropout ratio (ratio of dropout current to pickup current) may not be a suitable substitute for the distance relay, even for the locked-rotor protective function. It should reliably pick up on locked-rotor current and reliably drop out during starting to cutoff the timer before the elapse of the permissible locked-rotor time.

Mechanical speed switches are available for shaft mounting to indicate that rotor rotation has begun. They have been used in some critical cases to supervise a locked-rotor protective device.

7.4.4 Switchgear, Substation, and Motor Control Center Protection

Switchgear, substation, and motor control centers are the parts of the power system used to direct the flow of power and to isolate equipment and circuits from the power system. This equipment typically includes buses, circuit breakers, fuses, disconnecting devices, starters, instrument transformers, and the structure on or in which they are mounted.

To isolate faults in the buses, all power source circuits are disconnected from the bus by electrically operated relays or direct trip devices on circuit breakers or fuses. This disconnection shuts down all loads and associated processes supplied by the bus, so it is very important that bus protective relaying operate properly. It should isolate only the faulted area quickly and accurately to prevent injury, excessive damage, and unnecessary equipment shutdown. False tripping on faults in other parts of the power system is unacceptable.

To prevent faults, the switchgear, substations, and motor control centers should be installed in a relatively clean area free from dust, dirt, and moisture. In addition, a preventative maintenance program is needed to keep the equipment clean, to detect deterioration, to make repairs, and to check relay and circuit breaker performance.

As with motors and transformers, these buses usually are specifically protected against overcurrent faults and ground faults. Overloads usually are not considered a problem with buses, as long as the continuous current rating of the bus is taken into consideration and is correct. This rating should be chosen during the initial power system design, leaving sufficient margin for load growth. Bus overcurrent protection, whether it be relays or fuses for switchgear buses, circuit breakers with built in trip devices, or fuses for unit substation or motor control centers, usually consists of inverse time overcurrent protection.

Bus overcurrent protection should be coordinated to differentiate between faults on the bus and those further down in the power system. Differential protection can be added to medium-voltage buses to provide more sensitive and higher-speed protection. This protection will overlap other types of protection, thereby increasing the accuracy and sensitivity of the system protection. This differential protection is provided to supplement the overcurrent protection and is sometimes used on 15 kV buses and rarely used on 5 kV and low-voltage buses. The need for differential protection can be determined by studying the following items:

- 1) *Degree of Exposure to Faults.* Is the bus in a dirty, humid, or outdoor environment where it is subject to more deterioration than in cleaner areas.
- 2) *Coordination with Other Parts of Power System.* Can only overcurrent protection of the bus be coordinated with all other parts of the power system to prevent unnecessary disconnection of unfaulted parts of the power system that could cause significant loss of process equipment.
- 3) *Coordination with Backup Power Supplies.* On systems with more than one bus tie breaker and backup sources, differential protection can clear the faulted bus quickly so that other buses are not affected.

The types of differential protection used are current difference, current actuated with restraining coils, and voltage actuated. The types used will depend on economics, speed, and power system coordination. Current difference, the least expensive type of differential protection, uses simple overcurrent relays connected to respond to any difference between currents fed into the bus and the current fed from the bus. When current difference relaying is too slow and insensitive, a differential voltage relay is used.

Protection against voltage surges due to lightning, arcing, or switching is usually needed either on all switchgear or somewhere in the power circuit. In places where the power system is mostly indoors, surge protection is added to the transformers. Because of the lower levels of ground fault current in power systems, separate protection is usually needed to detect, alarm, and/or clear ground faults. Solidly grounded and low resistance grounded systems require sensitive and immediate ground fault detection and clearing. Ungrounded and high resistance grounded systems, 5 kV and lower, can be alarmed on a ground fault, thus allowing the plant operators to manually locate and clear the fault. Because of the damage involved with ground faults on high resistance grounded 15 kV systems, it is recommended that these faults be cleared immediately.

7.4.5 Cable Protection

Cables are considered the lifelines of any plant because they transmit power, control, and instrumentation signals. They also need short circuit, overload, and physical protection. The best protection for cables is the proper selection and rating/derating to match the required environmental, raceway, and load conditions.

This section will cover the application of protective devices to cable. The selection of any physical protection of cable is covered in other sections.

A cable should be protected from overheating due to excessive overload or short-circuit flowing in its conductor and shield. The fault may be in the cable itself or in another portion of the electrical system connected to the cable. Protection from damaging short-circuit currents should be provided by instantaneous devices. Rapid fault clearing will prevent the heat generated by the I^2R losses in the conductor during the fault from damaging the sheath.

Once the following items have been determined, the cable size can be determined, or the protection can be verified.

- 1) Maximum available short-circuit currents
- 2) Maximum conductor temperature that will not damage the insulation

3) Longest time that the fault will exist and the fault current will flow

Fig 7.10 is used to check for protection against conductor fusing. Fig 7.11 is used to check for protection against insulation damage at particular values of short-circuit current. A cable should also be protected from overheating due to overload current flowing in its conductor. The overload/2R heat losses in the conductors tend to elevate the cable temperatures to levels that, over a period of time, will damage the cable insulation and jacketing but will not damage the conductors. Therefore, cables are protected from current overload conditions with protective devices with thermal characteristics that are sensitive to the current and the length of time that this current flows. Similar to short-circuit conditions, Figs 7.10 and 7.11 can be used to verify the protection of the cable. However, for overload conditions, the cable-insulation damage curve will be of primary importance and the conductor fusing curve will be of secondary importance.

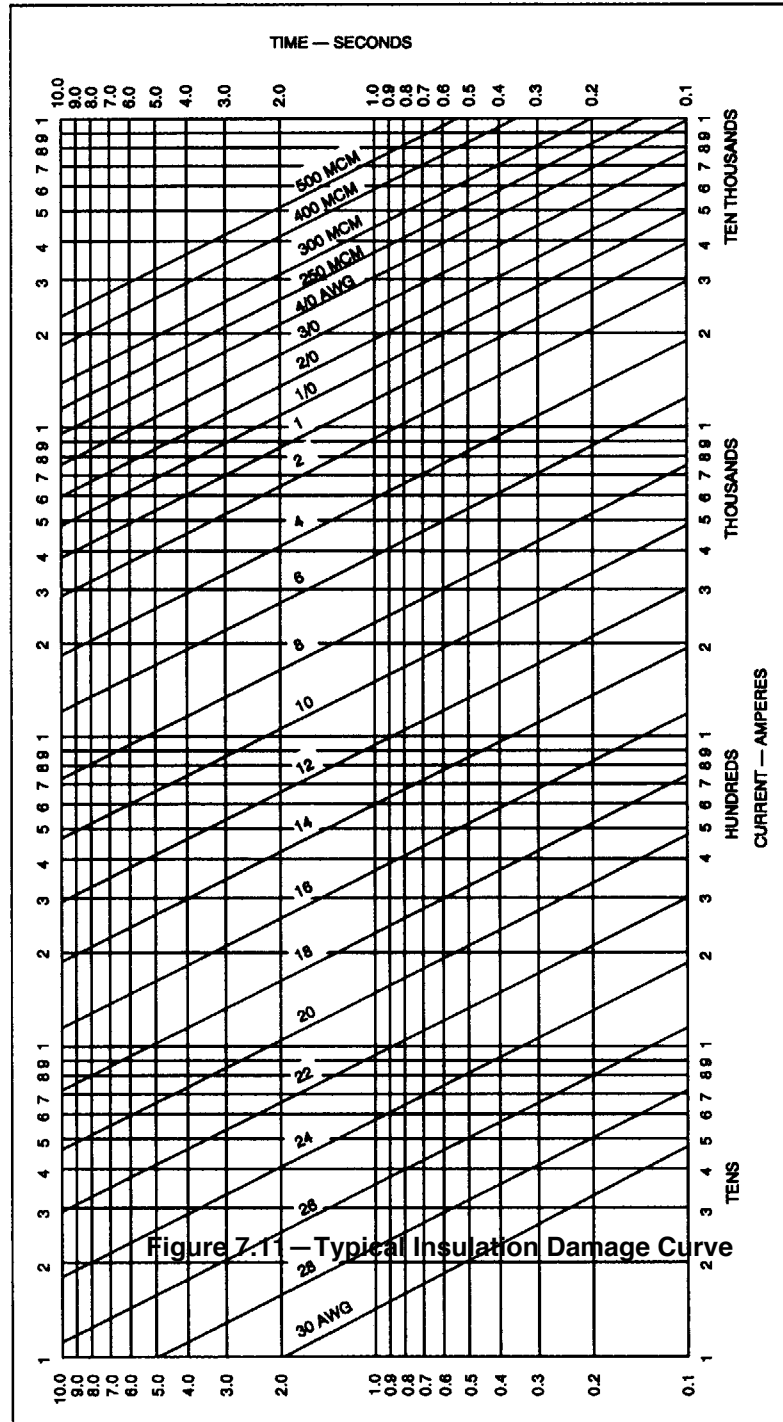
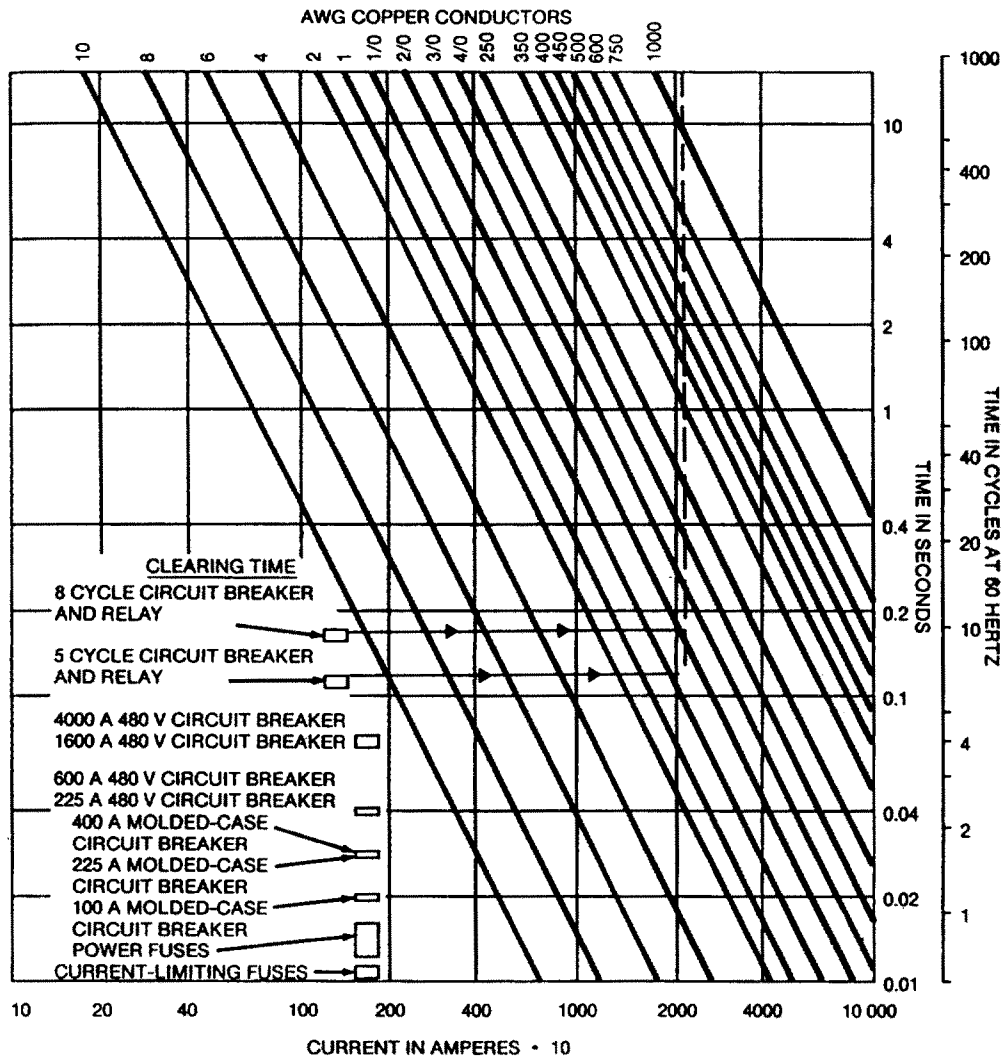
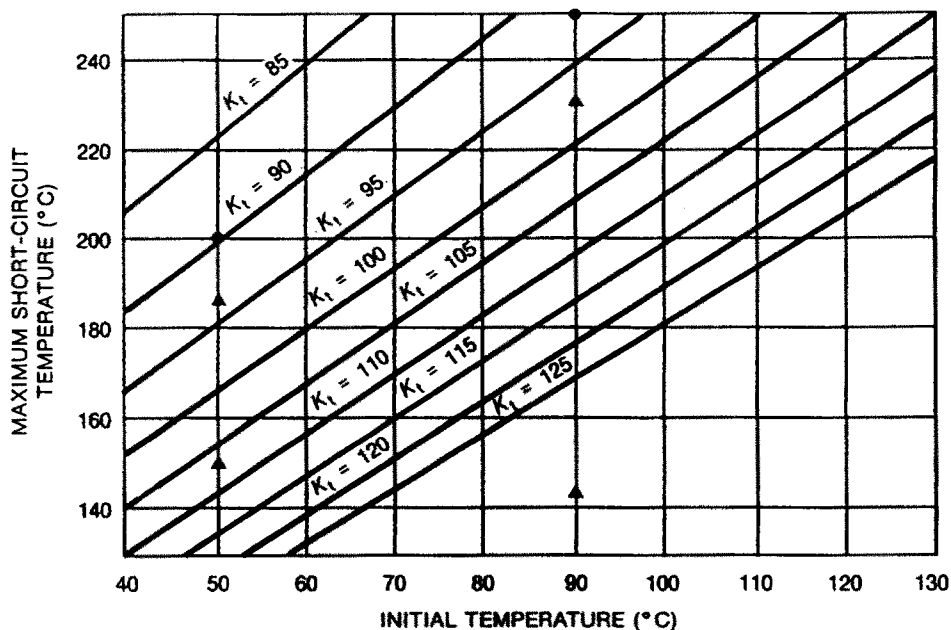


Chart showing fusing current for conductor sizes from No. 30 Awg to 500 MCM from 0.1 to 10 s. Chart is based on the following assumptions: (1) Radiation may be neglected because of the short time involved. (2) Resistance of 1 cm² of copper at 0°C is 1.589 μ. (3) Temperature resistance coefficient of copper at 0°C is 1/234. (4) Melting point of copper is 1083 °C. (5) Ambient temperature is 40 °C.

Figure 7.10 – Typical Fusing Curve



(a)
**Maximum Short-Circuit Current for Insulated Copper
 Conductors; Initial Temperature 75 °C; Final Temperature 200 °C**



For cables rated at initial (operating) and final (maximum short-circuit) temperatures different from 75 °C and 200 °C, respectively, correction factors for use with Fig 7.11(a) may be determined by use of Fig 7.11(b). By this chart, a *correction factor* is obtained by which the actual available fault current is converted to a *virtual available fault current* that is often used with Fig 7.11(a). The actual available fault current is multiplied by the correction factor K_t to obtain the *virtual available fault current*.

Examples:

- (1) Initial temperature = 50 °C
Maximum fault temperature = 200 °C
 $K_t = 0.899$
Actual available fault current = 20 000 A
Virtual available fault current = $0.899 \cdot 20\ 000 = 17\ 990$ A
- (2) Initial Temperature = 90 °C
Maximum fault temperature = 250 °C
 $K_t = 0.925$
Actual available fault current = 20 000 A
Virtual available fault current = $0.925 \cdot 20\ 000 = 18\ 500$ A

(b)
**Correction Factors K_t for Initial and
Maximum Short-Circuit Temperatures**

Figure 7.11 — Typical Insulation Damage Curve (Continued)

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8. System Grounding

8.1 Foreword

Grounding, as discussed in this section, is restricted to the grounding of electric power systems. In all cases, the equipment frame or enclosure should be electrically connected to the station ground mat or grid. Although emphasis is placed on grounding the generating station auxiliaries power service system, many of the same considerations will apply to other types of electric systems.

The user of this guide is encouraged to study references [2]¹, [3], and [6] to permit a more thorough evaluation of the grounding method to be used in any given installation.

Grounding or bonding for personnel safety is not included in this section because it is more appropriately covered in other documents, see [1] and [5].

8.2 Introduction

The purpose of connecting the neutral of a three-phase power supply generator or transformer to ground is to stabilize or control the voltages between the phase conductors and ground and to provide a return path for ground current required to operate protective devices during line-to-ground faults. The return path of ground-fault currents should be a metallic conductor, such as a cable sheath or conduit, that is routed with or encloses the phase conductors, but the return path may include the earth. Except for loads served at 120/240 V, 208/120 V, and 480/277 V, power plant auxiliaries are assumed to be balanced three-phase loads for which a neutral-current circuit is required only during ground-fault conditions.

A power system may be ungrounded (i.e., with no intentional conductor between the system or supply equipment neutral and ground), or it may be grounded in one of several ways. The service voltage and types of loads served are factors in determining the grounding method to be used or whether to operate a system ungrounded.

8.3 References

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[2] IEEE C62.92-1987, IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems, Part I — Introduction (ANSI).³

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[6] IEEE Std 142-1982, IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems (ANSI).

¹The numbers in brackets correspond to those of the references in 8.3.

²NFPA publications are available from Publications Sales, National Fire Protection Association, 1 Batterymarch Park, P.O. Box 9101, Quincy, MA 02269-9101, USA.

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8.4 Definitions

The following definitions, found in references [2] and [6], are listed here for convenience:

R_0	= Zero-sequence resistance of the system
X_0	= Zero-sequence inductive reactance of the system
X_{c0}	= Zero-sequence capacitive reactance to ground of the system
X_1	= Positive-sequence inductive reactance of the system
Z_0	= Zero-sequence impedance of the system
Z_1	= Positive-sequence impedance of the system

NOTE — All of the above are per-phase values. The zero-sequence impedance of a grounding device is three times the actual impedance of the device.

ungrounded: No intentional system grounding connection.

solidly grounded: No intentional grounding impedance.

effectively grounded: Permits the use of reduced rated (80%) surge arresters.

$$R_0 \leq X_1, X_0 \leq 3X_1 \text{ (see [6])}$$

reactance grounded:

$$\text{Low Inductance: } 3 < \frac{X_0}{X_1} < 10; 0 < \frac{R_0}{X_1} < 1 \text{ (see [6])}$$

$$\text{High Inductance: } X_0 \leq 10X_1 \text{ (see [6])}$$

low-resistance grounded: Intentional insertion of resistance into the system grounding connection.

$$R_0 \geq 2X_0; 0 < \frac{R_0}{X_1} < 10 \text{ (see [6])}$$

high-resistance grounded: The insertion of a high resistance into the grounding connection.

$$\frac{R_0}{X_1} > 100; \frac{R_0}{X_0} \leq (-1) \text{ (see [6])}$$

grounded for serving line-to neutral loads: $Z_0 \leq Z_1$

8.5 Transient Overvoltages

The voltage and current relationships between the phase conductors, neutral, and ground are affected by a number of electrical phenomena. An ungrounded system with no intentional conductive path to ground has a path for alternating currents to flow between the phase conductors and ground through the distributed capacitance-to-ground of circuits and equipment windings and any surge capacitors or power-factor correction capacitors connected to ground. This capacitance is a significant factor in the generation of transient overvoltages during an arcing ground fault. A fault to ground, in a cable or other circuit element, that is alternately initiated and cleared on an otherwise ungrounded system can result in transient overvoltages on the unfaulted phases that may reach several times the value of the normal crest of the phase-to-neutral voltage. Theoretically, the maximum overvoltage possible is limited only by the dielectric strength of the arc path and that of the insulation of the unfaulted phases, but it actually seldom exceeds four to six times the normal phase-to-neutral crest voltage, see [10].

An arcing or intermittent fault is equivalent to switching and charging a capacitor every half cycle of the system frequency with the theoretical voltage buildup of Fig 8.6. The combination of capacitance and source inductance may result in a buildup of peak voltage at every restrike of the fault. Section 14 of reference [10] describes this mechanism of voltage buildup and the magnitude of voltages expected with various grounding methods.

Electrical cables have much more capacitance to ground than overhead circuits or buswork. In addition, some cable faults tend to be self-extinguishing at a current zero. Since most of the conductors in power plant service systems are cables, these systems are vulnerable to arcing or intermittent ground faults and the resultant high-transient voltages. Accordingly, additional conductor insulation and/or voltage surge protection is required for reliable operation of ungrounded systems.

Analytical studies have demonstrated that the magnitude of transient overvoltage can be limited by suitably grounding the system, see [10]. The magnitude of the overvoltages will depend on the method of grounding, the value of the grounding impedance, and the number of restrikes of the fault.

The overvoltages can be limited to approximately 2.5 times the normal phase-to-neutral crest voltage with resistance grounding, if the ohmic value of the grounding resistor is equal to or less than one third of the capacitive reactance between each phase and ground, see [10].

8.5.1 480 V Systems

Service systems rated at 480 V may be ungrounded, solidly grounded, or resistance grounded. There are conditions unique to this service voltage. The same possibility for transient overvoltage on this system exists as for a higher-voltage system. However, the insulation of equipment at this voltage level has more inherent per-unit voltage withstand capability. For example, the overpotential test voltage of $2E+1000$ for a 460 V motor indicates a withstand strength of 1920 V ac rms, or 4.17 times the motor voltage rating. Comparatively, a 4000 V motor has a withstand strength of 9000 V ac rms, or 2.25 times the voltage rating. It is for this reason and for reasons of service continuity that some system designers will operate a 480 V system ungrounded but will ground a higher voltage system. In spite of the greater percent margin inherent in 480 V insulation, there have been cases of motor failure as a result of arcing grounds at that voltage level. There have also been incidents of voltage transformer damage from neutral instability on ungrounded 480 V systems, see [9] and [11].

8.6 Selection of Grounding Method

Power service systems in a generating station are either solidly grounded, resistance grounded, high-resistance grounded, or ungrounded. The 120/240 V and 208/120 V systems are always solidly grounded. The 480 V systems may be solidly grounded, resistance grounded, or ungrounded. However, even on solidly-grounded 480 V systems, the circuit and fault impedance at locations remote from the source may limit the fault currents to levels that will be difficult to detect.

Medium-voltage systems (2400 V to 13 800 V), are usually resistance or high-resistance grounded. Some medium-voltage systems are solidly grounded, but this could constitute an equipment hazard as described in 8.6.2.

8.6.1 Ungrounded Systems

Some systems are considered sufficiently important that they are not grounded and are allowed to operate under single-line-to-ground fault conditions. An ungrounded system does not allow the flow of damaging fault current during a single-line-to-ground fault. Normally, ground-fault detection is provided on these systems. The detection scheme alerts the operator to the ground-fault condition without interrupting the power supply to a process or essential equipment. Ungrounded systems involve risks of certain problems when a line-to-ground fault occurs.

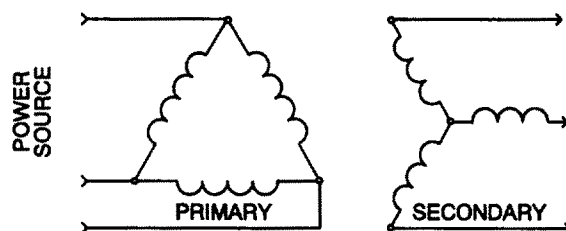


Figure 8.1 – Ungrounded System

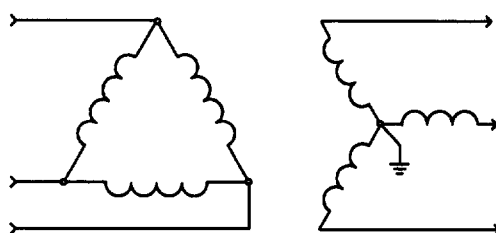


Figure 8.2 – Solidly Grounded System

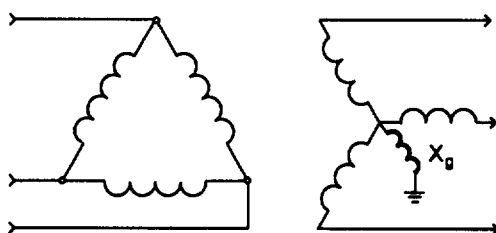


Figure 8.3 – Reactance Grounded System

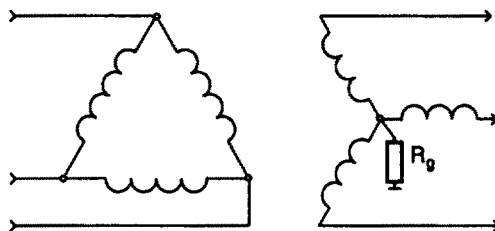


Figure 8.4 —Low Resistance Grounded System

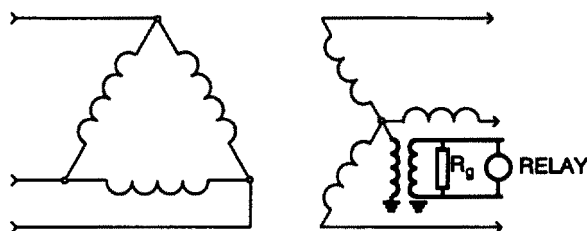


Figure 8.5 —High Resistance Grounding Utilizing a Single Phase Transformer and a Voltage Sensing Relay

Among the concerns are

- 1) The possibility of a second ground fault causing a two-phase-to-ground fault
- 2) Difficulty in locating the ground fault once it occurs
- 3) Transient overvoltages during an intermittent or arcing line-to-ground fault
- 4) Length of time acceptable for an orderly shutdown or transfer to an alternate source of power

Voltage transformers connected in wye and with the neutral or common point connected to ground on an otherwise ungrounded system are not considered to constitute a system ground. If voltage transformers are not heavily loaded with resistance, they may contribute to overvoltages and unbalanced conditions on an otherwise ungrounded system. The magnetizing reactance of the transformers coupled with system capacitance may cause neutral instability or neutral inversion usually associated with a condition described as “ferroresonance.” As defined in IEEE Std 100-1988 B2⁴, ferroresonance is a “phenomenon usually characterized by overvoltages and very irregular wave shapes and associated with the excitation of one or more saturable inductors through capacitance in series with the inductor.” Even systems that are normally grounded may be subject to this condition if the location of the system ground is such that, during switching operations, it can be isolated from a circuit that includes the voltage transformers. Such voltage transformers should be loaded with resistors to control ferroresonance.

⁴The numbers in brackets, when preceded by the letter “B,” correspond to the Bibliography in 8.11.

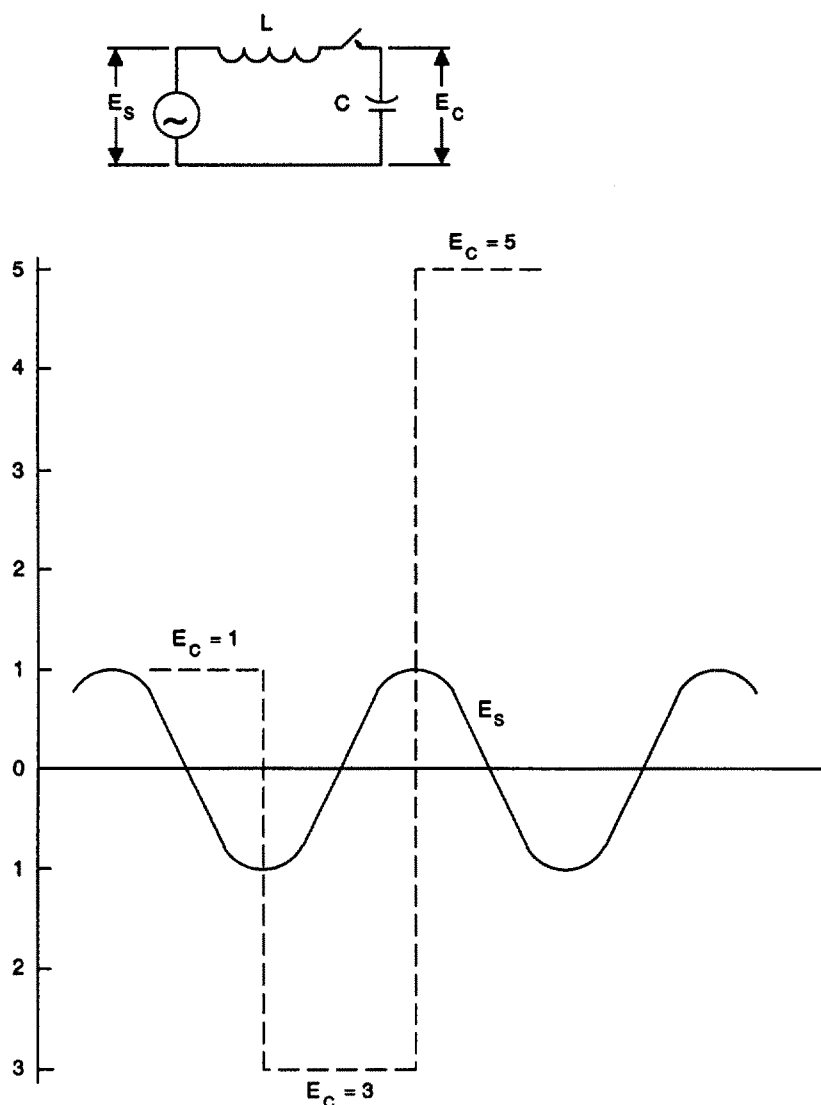


Figure 8.6 — Theoretical Buildup of Voltage During an Intermittent Ground Fault

8.6.2 Ground-Fault Damage

The ground-fault current to be permitted is related to acceptable ground-fault damage. Generating station service system loads are primarily motors. When a ground fault occurs in a motor, the fault current path may include the magnetic steel core of the stator. If so, damage to the core may require repair and partial or complete replacement of the laminations. It may, therefore, be prudent to limit the amount of fault current and the duration of the fault.

During a fault, the metal in the immediate area of the fault is usually vaporized. Since a constant arc voltage is assumed, the magnitude and time duration to which ground-fault currents should be limited, to minimize damage, can be determined by relating fault energy to ampere-seconds. It requires approximately 4000 kJ of energy to vaporize one pound of copper or steel. Arcing fault tests, reported in reference [7], were conducted on 480 V aluminum bus in steel enclosures. These tests indicated that 30 kJ is a threshold below which insignificant damage occurs. These same tests confirmed that arc voltage is essentially independent of fault current for a given gap. At 1000 A, the arc voltage varied from 50 V with a 0.2 in gap to 100 V for a 1.0 in gap. Accordingly, the 30 kJ threshold value of fault energy translates

to 600 and 300 As, respectively. Calculations, see [7], indicate that 53.5 kJ will vaporize $1/8$ in³ of aluminum or $1/20$ in³ of copper.

8.6.3 Ground-Fault Relaying Considerations

8.6.3.1 Ground-Fault Current Level

Ground-fault calculations are covered in Section 6., and ground-fault protection is covered in Section 7. However, these subjects are factors in the selection of a grounding method and some discussion of them is appropriate here.

Ground-fault-detecting current relays are sometimes connected in the common or residual circuit of current transformers, as shown in Fig 8.7. Where this is done and where selective tripping is to be accomplished, the fault current is typically limited to a value equal to the primary-current rating of the largest current transformers. This practice usually results in the maximum ground-fault current being approximately equal to the full-load rated current of the power-supply transformer.

Justification for this is based on the 5 A secondary rating of the current transformers. With an overcurrent relay having a minimum available setting of 0.5 A, the grounding impedance selected would permit ten times the relay pickup current during a zero-impedance fault. This will assure reliable relay performance (i.e., a fault with sufficient impedance to limit the current to one-fourth of the maximum value would still result in predictable performance of the overcurrent relay for selective operation of protective relays on breakers in series).

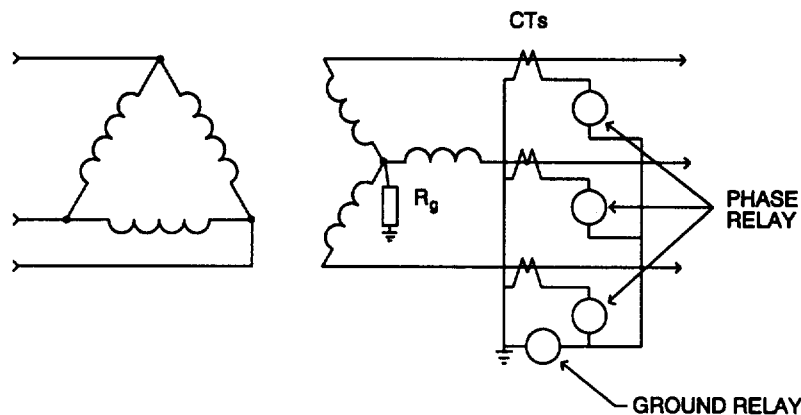


Figure 8.7 — Ground Relay Connected in Current Transformer Residual Circuit

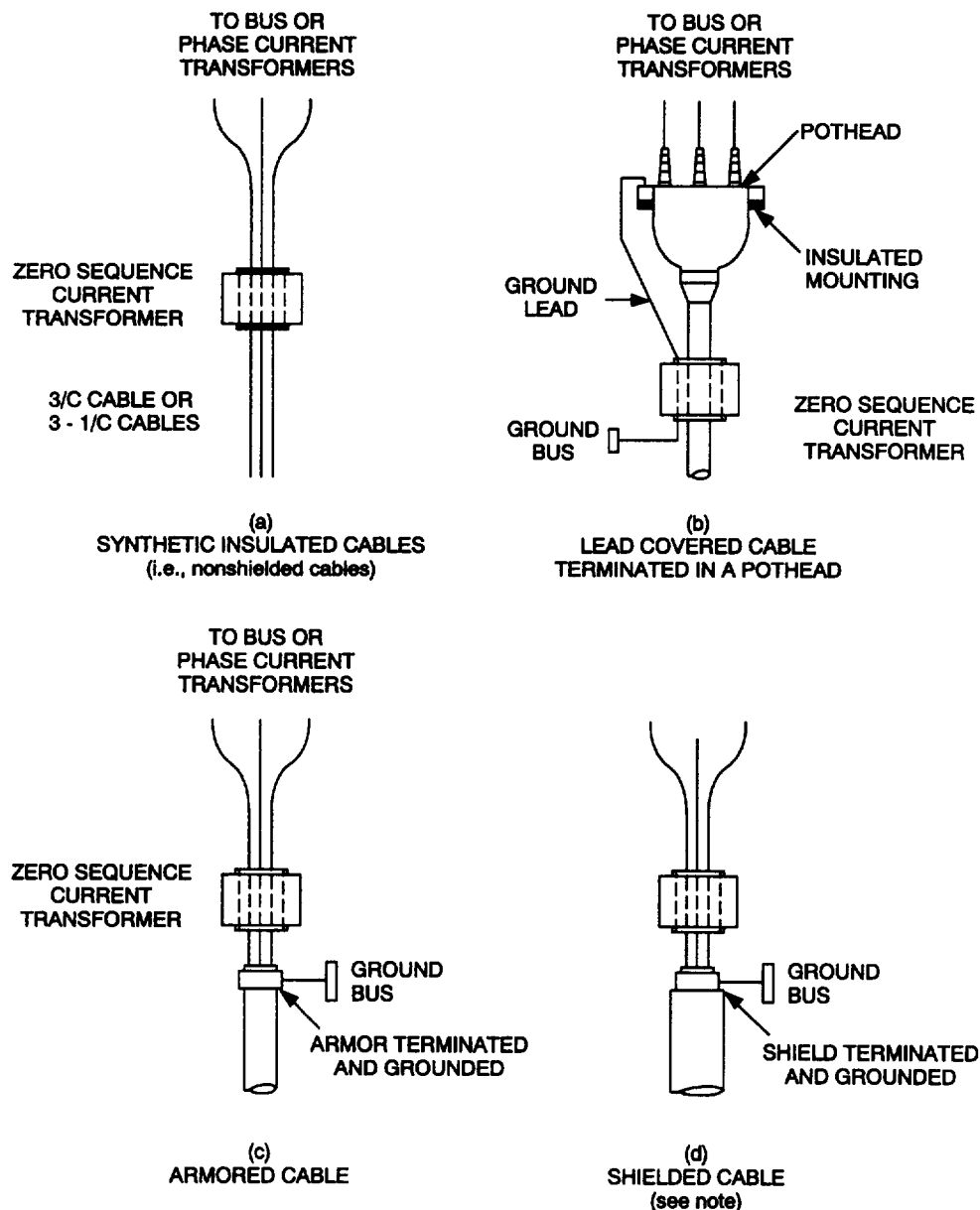
8.6.3.2 Zero-Sequence Current Transformer

The availability and application of the window-type core balance or zero-sequence current transformer (CT) and a sensitive overcurrent relay permits limiting ground-fault currents to a very low value. In this system, the three-phase conductors are passed through the window of a CT that has a magnetic core around which a secondary winding circuit is wound. With balanced three-phase currents, there is essentially no magnetic flux induced in the core and no output from the secondary winding. A ground fault will result in unbalanced currents that produce a net magnetic flux that will, in turn, cause a secondary winding output current proportional to the phasor sum of the phase currents.

In a three-phase, four-wire system, the phasor sum of the currents in the four conductors is zero during normal (nonfault) conditions. If this protective scheme is used on such a system, the three phase conductors and the neutral conductor must be passed through the window of the zero sequence CT. If a ground fault occurs to anything *except the neutral conductor*, it will cause a flux unbalance and the fault will be detected.

Even with electromechanical relays, selective tripping may be accomplished with the ground-fault current limited to as little as 25 A. If the fault current is to be limited to very low values, the grounding resistance should never exceed $X_{co}/3$ with all circuits connected to the system.

Utilizing the core-balance or zero sequence CT requires correct ground connections to cable shields, metallic sheaths, or armor. Connect shields, sheaths, or armor to ground on the cable side of the CT only, as shown in Fig 8.8.



NOTE: If the cable shield passes through the CT before termination, the shield must be brought back through the CT before grounding.

Figure 8.8 — Recommended Cable Connections When Using a Zero Sequence Overcurrent Relay Scheme

8.6.4 Grounding Resistance Value

For situations in which resistance grounding is used, the grounding resistance value is selected to provide the fault current required to control transient overvoltages and allow acceptable fault sensing during a ground fault. The resistance should be high enough to minimize damage but low enough to permit adequate current for fault sensing. A determination must be made of the current value for a fault on a circuit at the end remote from the power source. The circuit impedance may be high enough to reduce the ground-fault current significantly below the maximum value, with the result being that the fault may not be detected or would not be cleared in a short time even if detected.

Many 2400 V service systems and some 4160 V systems are not grounded. Some 4160 V and most 6900 V and 13 800 V systems are low-resistance grounded, but some are high-resistance grounded through a distribution transformer with a secondary loading resistor. As indicated previously, the equivalent grounding resistance of the transformer primary circuit should be equal to or less than one-third of the system capacitive reactance when all circuits are connected to the system, i.e., $R_g \leq X_{co}/3$, where R_g is the grounding resistance as seen from the system being grounded, and X_{co} is the capacitive reactance-to-ground per phase and includes the capacitance of all cables, motor windings, transformer windings, surge or shunt capacitors, and other equipment connected to the system. When fewer than the total circuits are connected to the system, the capacitive reactance is higher, so the criteria of $R_g \leq X_{co}/3$ is always satisfied. Grounding by this method will probably require the core-balance or zero sequence CT protective relaying scheme if selective tripping of feeders is required. Selective tripping may not be assured even with zero sequence CT relaying on high-resistance grounded systems. This is especially true on small power systems where the value of R_g is chosen very close to $X_{co}/3$. If selective tripping is desired on such systems, the value of R_g may have to be much less than $X_{co}/3$.

If the ground current is not sufficiently high, a voltage-polarized-product-type directional-ground relay can be used with standard CTs. This relay utilizes zero sequence voltage and CT residual circuit current. A voltage-product-type relay gets part of the operating energy from the voltage and can operate on lower values of current than a conventional overcurrent relay.

The current or product-type ground relaying may be supplemented by a voltage-sensing relay connected across the resistor in the secondary of the grounding transformer for backup tripping of the main breaker(s), as shown in Fig 8.5.

8.7 Grounding Equipment Connections

To achieve a system ground connection, a neutral point should be available. It is possible to operate a delta-connected system with one phase conductor intentionally grounded, but this is not recommended because the other two-phase conductors operate continuously at a higher voltage above ground and should have additional electrical insulation.

The most convenient way to obtain a neutral point is by having the secondary windings of the supply transformer wye-connected. The common point of the wye provides the neutral point to connect to ground or to grounding equipment. At least one other set of windings on the transformer must be connected in delta for the transformer to be a ground current source as shown in Fig 8.2.

A wye-wye transformer with both neutrals grounded provides a path for ground currents, but the ground currents are limited, in part, by the grounding impedance of the primary source, and the transformer, therefore, is not a ground-current source. This connection should not be used on power plant service systems because selective tripping of service-system circuits may not be possible, and the sensitive ground-fault relaying on the generator neutral may operate to trip the unit for a single-line-to-ground fault or the service system.

Unit auxiliaries transformers have primary windings that are delta-connected and secondary windings that are wye-connected. If it is necessary to have no phase displacement between the primary and secondary voltages, the wye-delta-grounded wye or delta-grounded zig-zag connections are preferred to the two-winding, wye-wye transformer. These connections are illustrated in Figs 8.9 and 8.10, respectively. A T-T connection could also be used in this application; however, some unbalance in the secondary voltages will occur unless the transformer impedance is very low. This connection is shown in Fig 8.11.

If the transformer secondary winding is delta-connected, it will be necessary to establish a neutral point by means of a grounding transformer or bank. The grounding-transformer connection may be zig-zag (inter-connected wye) or wye-delta. Fig 8.12 shows ways by which a system ground may be established when no system neutral is available.

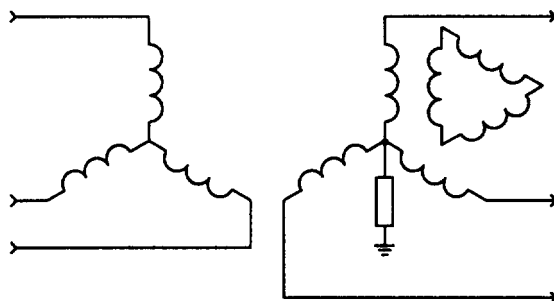


Figure 8.9 — Resistance Grounding of a Wye-Wye Transformer With a Delta Tertiary

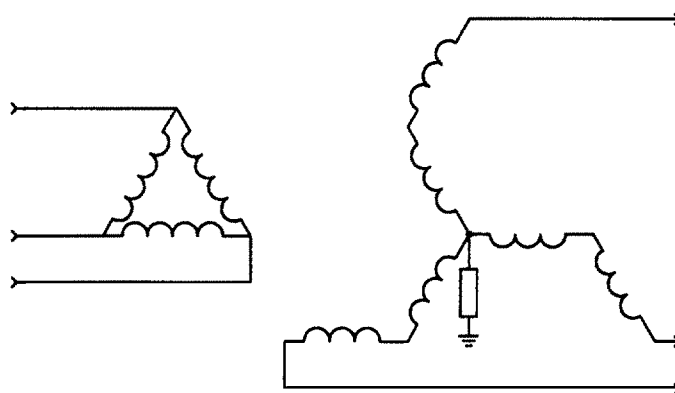


Figure 8.10 — Resistance Grounding With a Delta Zig-Zag Transformer

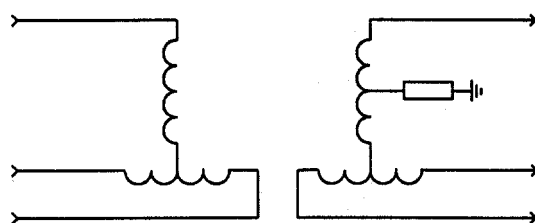


Figure 8.11 — Resistance Grounding With a T-T Connected Transformer

It is desirable to have the system grounding and the positive-sequence voltage source at the same location. When the ground location is other than at the positive-sequence voltage source, care must be exercised to ensure that the grounding equipment is connected to the system at all times. The grounding equipment may be connected to a main bus, but connecting it to the load side of a feeder breaker is discouraged.

8.8 Ground-Fault Current Calculations

Although fault current calculations are discussed in Section 6., some conditions are unique to ground-fault currents that permit simplification of the calculations.

8.8.1 Resistance-Grounded System

If the ground-fault current is limited to the full-load current value of the supply transformer or less, it is usually sufficiently accurate to ignore the transformer and source reactance in calculating the fault current and use only the grounding-resistor impedance. This assumes that the total source reactance is approximately 10% or less of the grounding-resistor impedance. The error will be approximately 0.5% or 5 A out of 1000. For this method of grounding, the capacitive component of current may also be neglected.

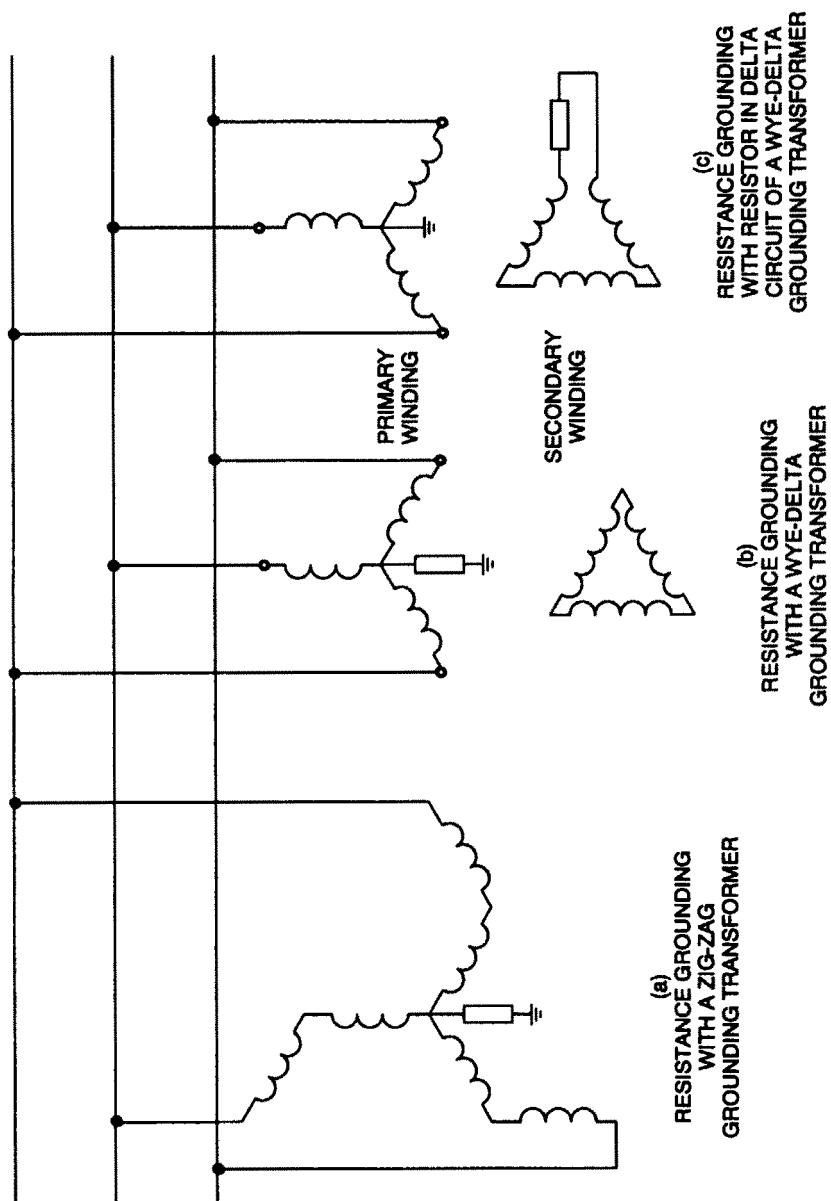


Figure 8.12 — Ways in Which a System May Be Grounded When No Neutral is Available

8.8.2 High-Resistance Grounded System

The general case of a single-line-to-ground fault requires that the positive, negative, and zero-sequence networks be connected in series to determine the sequence components of fault current. For the case wherein the fault current is limited to a very low value by a high resistance, it is sufficiently accurate to divide the phase-to-neutral voltage by the resistance of the grounding resistor. That is, $I_R = E_{LN}/R_g$. If a transformer is connected between the system neutral and ground with a resistor in the secondary circuit, as in Fig 8.5, the value to use for R_g is the resistor ohms multiplied by the square of the transformer turns ratio.

If $R_g = X_{co}/3$, the total ground-fault current will be $I_{fg} = I_R$ because the capacitive component of ground current is vectorially added to the resistive component (I_R).

8.9 Standby Generator Grounding

Selection of a grounding method for standby generators is related to the number of standby systems for each safeguard function, the methods for operating safeguard auxiliaries, and the criticality of the safeguard function. The most critical safeguard functions for large turbine generators are lubrication of the shaft and hydrogen seals and maintenance of the power supply to the turning gear motor. In some power stations, cooling and ventilation may also be a critical safeguard requirement. In addition to critical loads, there may be other loads that are less critical or can have the power supply interrupted for short periods of time (up to 1 min). These include sump pumps, ventilating fans, battery chargers, etc.

Load testing of standby generators is usually performed by connecting them to the station service system and picking up power system load.

8.9.1 Solid Grounding

When solid or low-impedance grounding is selected, protective relays and circuit breakers (or fuses) isolate ground faults as soon as possible. This will result in the shut down of a safeguard auxiliary or the standby generator. This is acceptable only if the safeguard auxiliaries are not critical or if additional standby auxiliaries and power supplies are available for critical safeguard functions.

Operation of a solidly-grounded standby generator in parallel with a solidly-grounded auxiliary system could result in unacceptable circulating current due to third harmonic or unbalanced voltages.

8.9.2 Ungrounded and High-Impedance Grounding

When standby generator neutrals are not grounded or are grounded through high impedance, a ground-detection system should be provided. This detection system may also be designed to reduce voltage-adding effects caused by arcing ground faults on ungrounded systems. The impedance of the fault detecting and the grounding circuit should limit ground-fault current to a value that will permit continuous operation with a single-line-to-ground fault. Location and removal of the faulted circuit may be difficult. However, noncritical loads may be switched off momentarily at anytime, and critical loads may be switched momentarily when the critical period has passed (1/2 to 1 h).

As previously discussed (see 8.5.1) 480 V systems with 600 V insulation have additional capability to withstand high voltages caused by arcing ground faults.

8.9.3 General

Solid or low-impedance grounding has the advantage of isolating ground faults on noncritical circuits with minimum hazard to critical safeguard functions. However, ungrounded or high-impedance grounding permits continuous operation with a single-line-to-ground fault but introduces the hazard of high voltages due to an arcing fault. Reliable failure rate information is not available for a mathematical analysis as to which method of grounding results in the

most reliable safeguard power service. Therefore, the method selected is a matter of judgment and the historical experience of the owner.

8.10 Summary

Most power plant systems fall into four basic categories of grounding, as follows.

8.10.1 Solidly-Grounded System

With this method, faulted circuits and equipment are isolated in the minimum time possible. A disadvantage of this method is the damage due to high fault currents. Also, equipment essential to the output of the generating unit may be disconnected under fault conditions.

8.10.2 Resistance-Grounded System

With this method, as for solidly-grounded systems, faulted circuits and equipment are disconnected as quickly as possible but fault damage is reduced. The magnitude of fault current allowed is determined by the protective relaying requirements. This relaying includes the circuit relaying, transformer breaker relays, and transformer neutral relays. Consideration should be given to the requirement for differential relays to operate in case of a ground fault in their zone of protection.

8.10.3 High-Resistance Grounded System

With this method, the low value of fault current may not allow a selective relaying scheme. In some cases, the system could operate indefinitely for a single ground fault, but the fault should be isolated as quickly as possible to preclude the occurrence of a two phase-to-ground fault. A low value of fault current (in the order of 5 to 7A) may not cause extensive damage if the equipment is isolated within a reasonable time (i.e., the time associated with an orderly shutdown of the circuits involved). In general, isolating faulted circuits or equipment should not result in a generating unit trip or reduction in output. In either resistance grounded or high-resistance grounded systems, it is expected that the transient voltages will be limited to values that will not be detrimental to the system equipment.

8.10.4 Ungrounded System

With this method, relaying is used to indicate that a ground fault exists, and the system continues in service until manually controlled switching can isolate faulted equipment. There is the risk of excessive transient voltages that could damage other equipment. It is also difficult to locate the fault once it is detected.

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9. Transformers and Voltage Regulation

9.1 Introduction

This section reviews requirements for the application and purchase of transformers used in electric power service systems for electric generating stations.

Power service transformers in generating stations require special consideration because their reliability impacts upon the reliability of the generating unit.

9.2 Scope — System Configurations

Different system configurations are used to supply power to generating station auxiliaries. These are discussed in Section 3. However, some basic systems are assumed because the system configuration has a definite impact on some transformer variables such as bracing, harmonic control, and ground fault protection. The most frequently used system for generating stations employs a unit auxiliaries transformer or transformers connected to the generator bus, a station service (startup) transformer connected to a high-voltage system at the station, and substation (load center) transformers connected between the medium-voltage buses and the low-voltage buses. A number of smaller transformers for lighting and other functions are also used, but these will not be considered in this section.

The use of a generator breaker or generator load-break switch has become more frequent in the last several years. This section covers, in general, the conditions in which there are no generator breakers or load-break switches. Most information is applicable to either condition. However, the use of generator breakers or load-break switches may eliminate some problems involved with faults on the unit auxiliary transformer or the problem of transferring of the medium-voltage system.

9.3 References

[1] ANSI C57.12.10-1987, American National Standard Requirements for Transformers 230 kV and Below, 833/958 through 8333/10 417 kVA Single-Phase, and 750/862 through 60 000/80 000/100 000 kVA Three Phase.⁵

[2] ANSI C57.12.30-1977 (Withdrawn), American National Standard Requirements for Load-Tap-Changing Transformers 230 000 V and Below, 3750/4687 through 60 000/80 000/100 000 kVA, Three-Phase.

[3] IEEE C57.12.00-1987, IEEE Standard General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers (ANSI).⁶

[4] IEEE C57.13-1978 (Reaf 1986), IEEE Standard Requirements for Instrument Transformers (ANSI).

[5] NEMA TR-1-1980, NEMA Standards Publication for Transformers, Regulators, and Reactors.⁷

9.4 Definitions

station service (startup) transformer: A transformer that supplies power from a station high-voltage bus to the station auxiliaries and also to the unit auxiliaries during unit startup and shutdown and/or when the unit auxiliaries transformer is not available.

substation (load center) transformer: A transformer that supplies an area or group of equipment containing switches, circuit breakers, and buses. (Transformers connected between the medium-voltage and low-voltage buses use this nomenclature.)

⁵ANSI publications are available from the Sales Department, American National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036, USA.

⁶IEEE publications are available from the Institute of Electrical and Electronics Engineers, Service Center, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA.

⁷NEMA publications are available from the National Electrical Manufacturers Association, 2101 L Street NW, Washington, DC 20037, USA.

unit auxiliaries transformer: A transformer intended primarily to supply all or a portion of the generating unit auxiliaries.

unit transformer: A power-system-supply transformer that transforms all or a portion of the unit power from the unit to the power system voltage. (Not within the scope of this section.)

9.5 Voltage Range

The voltage range of the auxiliaries power system is the result of selecting transformer taps, voltage regulating devices, impedance, and loads. Selection of transformers requires a knowledge of the acceptable voltage range, regulation, and the equipment short-circuit duty. (Section 9.7 below addresses the more common problems of voltage range. Section 6. addresses short-circuit calculations.)

9.6 Specification of Transformers

9.6.1 General

The specification is the communicating document that describes the equipment requirements in detail to the manufacturer. It should be as complete as possible to ensure that the correct equipment will be manufactured and tested. The following is a list of the most important items to be considered in a transformer specification.

9.6.2 Specification Content

- 1) Rating in kVA — temperature rise and methods of cooling
- 2) Service conditions
- 3) Voltage ratings and taps
- 4) Insulation level (BIL)
- 5) Connection and phase shift
- 6) Impedance and frequency
- 7) Terminal facilities
- 8) Surge protection
- 9) Short-circuit capability
- 10) Sound level
- 11) Evaluation of losses
- 12) Accessories and protective devices
- 13) Tests, test reports, data
- 14) Tank and foundation requirements
- 15) Shipping requirements

9.6.3 Rating in kVA

9.6.3.1 General

The rating in kVA is specified so that the guaranteed average winding temperature rise will not be exceeded for a specified ambient temperature and continuous rated load. Keeping the temperature of the insulation below the guaranteed value is an important factor for longer life.

The standard average winding temperature rise for oil-immersed, self-cooled (OA) transformers is 65 °C, in accordance with IEEE C57 12.00-1987 [3]⁸ (previously 55 °C), when the ambient temperature averages 30 °C over 24 h but does not exceed 40 °C. If the ambient temperature exceeds these values, the transformers should be derated in accordance with the manufacturer's recommendation. Additional capacity ratings above the OA rating may be

⁸The numbers in brackets correspond to those of the references in 9.3.

obtained by adding fans (FA) or pumps and fans (FOA) for additional cooling. The additional capacity depends on the size of the transformer.

Available percentage increases in capacity are 15%, 25%, 33%, or 67% (two stages of cooling). In addition, some transformers are given a rating based only on forced-oil and air (FOA) cooling and temperature rise. These transformers do not have an OA rating, and it is necessary to have the fans and pumps operating when the transformer is energized. The requirement for fans and pumps in a transformer with an FOA rating reduces the reliability by a small degree.

Water-cooled transformers (FOW) are used in some installations. The transfer of heat, in this case, is from the transformer oil to a water system that removes it from the transformer. Standard temperature rise is based on average water temperatures of 25 °C over a 24 h period that do not exceed 30 °C.

Dry-type substation transformers are frequently used inside the plant so that, in case of failure, there will be no burning oil. (Vapor-cooled and encapsulated coil transformers may also be used.) Ventilated dry-type transformers use ambient air for cooling. The standard temperature rises are 80 °C, 115 °C, and 150 °C above an ambient that averages 30 °C over a 24 h period, but does not exceed 40 °C (most applications use 150 °C temperature rise). Forced-air cooling may also be used to obtain a higher rating.

Gas filled and less flammable liquid filled (silicone and hydrocarbon liquids) transformers are two other types that may be used inside buildings as substation transformers without transformer vaults because they do not present a fire hazard. Oil-filled transformers may be used in buildings in vaults or may be located just outside of the building at a safe distance and provide the requirements for the building. The standard temperature rise of gas-filled transformers is 150 °C above an average ambient of 30 °C over a 24 h period, but does not exceed 40 °C. The temperature rise for less-flammable liquid filled transformers is 65 °C for the same ambient condition.

Transformers have thermal overload capabilities. Loading to these capabilities may cause a reduction in life. These capabilities, and the methods for calculating them, are described in IEEE C57.92-1981 [B9]⁹ and IEEE C57.96-1989 [B11].

9.6.3.2 Unit Auxiliaries Transformers

One, two, and three unit auxiliaries transformers typically are used per unit, but two are used most frequently to reduce load currents and fault currents and to improve reliability. The number used is highly dependent on unit size, startup configuration, total auxiliaries system load, boiler feed pump drives, flue gas conditioning, etc.

The kVA rating of these transformers is selected on the basis of normal and maximum expected load. An economic evaluation that considers the initial cost of the transformer installed plus the evaluated cost of losses is used to determine the type of cooling, such as OA, OA/FA, OA/FOA, OA/FA/FOA, etc. These transformers supply the unit auxiliaries and are loaded a large portion of the time. Losses will consist mostly of load losses and have a tendency to make an OA rating equal to normal load the most economical. During unusual operation of the auxiliaries system (one transformer out-of-service or startup of another unit), additional load may be carried with one or two stages of forced-air (FA) or forced-oil and air (FOA) cooling. The rating may be influenced by requirements for future additions to the system.

Normal loading is determined from a list of the motors and substation transformers supplied by the unit auxiliaries transformers. The loading of the motors and transformers should be obtained from the expected loading of driven equipment during normal operation. This may be considerably lower than the total of the nameplate ratings of the motors and transformers. A tabulation of the highest possible operating load that the transformer can experience should be considered to ensure that the transformer can also supply this load. Past experience indicates a load growth in the auxiliaries system; and this should be considered.

⁹The numbers in brackets, when preceded by the letter "B," correspond to the Bibliography in 9.8.

9.6.3.3 Station Service (Startup) Transformers

The kVA rating is selected on the basis of the normal load and maximum expected load. An economic evaluation that considers the initial cost of the transformer installed plus the evaluated cost of losses is used to determine the type of cooling, such as OA, OA/FA, OA/FA/FOA, etc. The selection of the size of this transformer is more difficult. It may be used for one unit or two or more units, or there may be more than one transformer per unit. In general, this transformer does not supply much load except during startup or when it is used as an alternate for a unit auxiliaries transformer. No-load losses will usually be a dominant factor in the economic evaluation. Because of this, maximum use of forced-cooling and short-time load capabilities may be most economical. For example, a transformer, with two stages of cooling required during startup of one unit while acting as an alternate source for auxiliaries of another unit, may supply its load at other times on its OA rating and still be adequate for the continuous load.

The continuous load that this transformer will carry should be tabulated because there is a tendency to add station load or loads common to several units on this transformer, which may result in an unacceptable overload during startup or when serving as the alternate for a unit auxiliaries transformer.

On other units, however, the station service transformer may be dedicated to one function (i.e., startup of a designated unit), and the criteria for sizing may be simple. In general, these transformers do not carry a sizable load for an extended period; therefore, forced-air cooling will be economical to supply the peak loads.

If unit auxiliaries are supplied by single-phase transformers with a spare, the requirement that the station service transformer be adequate for use as an alternate source upon failure of a unit auxiliaries transformer may be waived because of the short period required to replace the failed transformer with the spare. In some cases, alternate busing arrangements are used to reduce the time of reconnection.

9.6.3.4 Substation (Load Center) Transformers

These transformers are usually of a smaller rating than the unit auxiliaries or station service transformer, and there are usually several transformers to consider. There is a tendency to select as many as possible of the same size to limit the number of sizes used. Again, the transformer cooling should be evaluated on an economic basis. It will be loaded usually with the unit it serves. If the transformer is the sole supply to the load, its OA rating at 65 °C (or 150 °C for dry type) rise should supply normal continuous load with unusual load or ambient conditions being supplied with one or two stages of forced cooling. Another possibility to be evaluated is the use of larger transformers. If a transformer is also used as an alternate for another transformer (when the other transformer is out of service), then the forced-cooled rating is specified to supply both its normal load and the alternate load under normal continuous loading conditions.

During the design of power plants, a complete list of the low-voltage power utilizing devices is not usually available when selecting transformer sizes. Frequently, additional loads are added later, and, therefore, a certain amount of estimating is associated with the sizing of these transformers. In some cases, it may be desirable to purchase provisions for forced cooling to be added later.

9.6.4 Service Conditions

9.6.4.1 General

Transformer standard IEEE C57.12.00-1987 [3] defines usual as well as unusual service conditions. These should be reviewed, and applicable unusual conditions such as high (or low) ambient temperatures, wind, snow, ice loading, high altitudes, contamination and restricted air flow, increased harmonic factor due to the nature of the load to be supplied, as well as usual conditions should be included in the specification.

9.6.4.2 Unit Auxiliaries Transformers

These transformers are usually oil-immersed and are therefore located outside of the generating station building rather than in a vault inside the building. Normally, there are no problems with this arrangement, but attention should be given to the flow of hot air so that the cooling system of one transformer does not affect another located nearby.

9.6.4.3 Station Service (Startup) Transformers

The high-voltage connections and oil-immersed construction requires the transformer to be located outside of the building. See unit auxiliaries transformers above.

9.6.4.4 Substation (Load Center) Transformers

These transformers are usually located within the building, and they may be oil-filled (in vaults), nonflammable liquid-filled (for indoor service), inert gas insulated, or dry-type. Also, some are oil-filled and located outside of the building. Alternative cooling methods should be considered in relation to fire hazards, environmental effect, and cost. They may also be exposed to dust laden atmospheres for short periods. Encapsulated coil and vaporization-cooled transformers are gaining a broader acceptance.

9.6.5 Voltage Ratings and Taps

9.6.5.1 General

The voltage range ratings of the two or more windings should be specified along with the taps (if required) and any special requirements, such as unusual taps. When taps are required, the usual arrangement is two full capacity 2.5% taps above and two full capacity 2.5% taps below rated voltage. A deenergized tap changer (DTC) is usually on the high-voltage winding of the transformer and may be changed only when the transformer is deenergized.

In some cases, due to system voltage regulation problems, it is necessary to use load-tap-changing (LTC) transformers. These transformers are generally less reliable and more expensive due to the complexity of design and moving parts. Therefore, their application should be carefully evaluated among other reliable and economical methods available. When LTC transformers are used, there may be either manual or automatic control of the tap-changing mechanism.

9.6.5.2 Unit Auxiliaries Transformers

These transformers are connected most often to the generator bus. The generator bus will normally have a voltage range of $\pm 5\%$ for the standard generator voltage rating. The transformer high-voltage rating is frequently selected to be equal to the generator voltage rating with two 2.5% taps above and two 2.5% taps below rated voltage. Another practice is to select the high-voltage rating to be 0% to 5% below generator rated voltage with two 2.5% taps above and two 2.5% taps below transformer rated voltage. In this case, the possibility of overexcitation should be thoroughly reviewed. The low-voltage rating is normally of the medium-voltage class (2.4 kV, 4.16 kV, 6.9 kV, 13.8 kV, etc.), which is approximately 4% or 5% above the rated voltage of the medium-voltage motors (2.3 kV, 4 kV, 6.6 kV, 13.2 kV, etc.). If voltage conditions (present and future) permit, elimination of the taps is desirable. In places where taps are required, the usual arrangement is to provide four taps in addition to the rated-voltage tap.

Should these transformers be connected to a high-voltage substation instead of the generator bus, the high-voltage rating is selected to be equal to the nominal voltage rating of the high-voltage bus on the basis that its voltage will vary $\pm 5\%$ during normal operation. If the variation is more than $\pm 5\%$, consideration should be given to a different voltage selection or different taps. In general, two 2.5% taps above and two 2.5% taps below the nominal voltage rating are selected to allow for future changes in the substation voltage range. However, any number of taps may be specified above and/or below the nominal-voltage rating. The low-voltage rating is usually of the medium-voltage class.

9.6.5.3 Station Service (Startup) Transformers

The voltage rating and tap selection should use similar application principles as for a unit auxiliaries transformer connected to a high-voltage substation.

9.6.5.4 Substation (Lead Center) Transformers

The high-voltage rating is usually specified to be equal to the nominal voltage of the medium voltage bus. The low-voltage rating is specified to be equal to a nominal low voltage approximately 4% or 5% above the voltage rating of the low-voltage motors. Taps (normally two 2.5% above and two 2.5% below rated voltage) are usually specified in the high-voltage winding to allow adjustment of the voltage range after experience is obtained with operation of the system. Taps may be specified below the normal tap, above the normal tap, or divided between the two.

9.6.6 Insulation Level

9.6.6.1 General

The insulation level is designated by the basic lightning impulse level (BIL), which indicates the ability of a transformer to withstand a voltage surge of a standard $1.2 \times 50 \mu\text{s}$ wave such as might be experienced due to lightning.

Standard values of BIL have been established, as well as other test voltages that the transformer should withstand for a given voltage rating. The test values and a description of the test requirements are given in IEEE C57.12.00-1987 [3].

Bushings are provided with the transformer, but they have different insulation ratings. Special requirements can be met if specified for such things as high BIL, extra creep distance, higher switching-surge rating, etc.

The BIL of dry-type and inert-gas-filled transformers will be different from those of liquid-immersed transformers. There is also a difference in the BIL level for power and distribution transformers.

9.6.6.2 Unit Auxiliaries Transformers

When the transformer is connected to the generator bus, the high-voltage BIL rating is usually specified equal to or greater than that of the nearest voltage class above the generator rated voltage. It should be recognized that the BIL of the isolated phase bus is usually lower than that of the transformer. This reduced BIL of the bus is compatible with [B3]–[B5] and is consistent with the surge voltage strength of the generator, which is also lower than that of the transformer. The low-voltage winding BIL is usually specified to be equal to or greater than that of the nominal voltage class of the medium-voltage bus.

If the unit auxiliaries transformer is connected to the high-voltage substation, the BIL is determined in the same manner as for the station service transformer.

9.6.6.3 Station Service (Startup) Transformer

The BIL for the high-voltage winding is selected to be consistent with the insulation coordination for the high-voltage system. The low-voltage winding BIL is selected to be equal to or greater than that of the voltage class of the medium voltage bus.

9.6.6.4 Substation (Load Center) Transformer

The BIL of the high and low-voltage windings should be equal to or greater than that of the voltage class of the system, to which they are connected.

9.6.7 Connections

9.6.7.1 General

Transformer banks may be made of one three-phase or three single-phase transformers. The windings may be connected in wye or delta configuration, and they may be grounded, ungrounded, or grounded through impedances. In addition, the transformers may have two, three, or more windings. The overall connection through the unit transformer, unit auxiliaries transformers, and station service transformers should be coordinated to allow an open (dead) or closed (live) transfer of the auxiliaries supply from the station service transformer to the unit auxiliaries transformer. This requires that the connections of all of these transformers be considered together to determine acceptable phase relationships. When closed transfers are made, the available short-circuit current due to the unit auxiliaries and station service transformers being in parallel may be greater than the interrupting capability of the circuit breakers. Therefore, the duration of the interval in which the unit and station transformers are paralleled should be minimized to reduce the possibility of faults occurring during this time. Whether a three-phase transformer or three single-phase (with one spare) transformers are used is a matter of economics and reliability. The loss of generating capacity resulting from an auxiliary transformer failure will influence the evaluations.

9.6.7.2 Unit Auxiliaries Transformer

The windings of these transformers are connected usually in a wye configuration on the medium voltage side to provide a neutral point for grounding the medium-voltage system. In order for the transformer to provide a ground current source and voltage stability, one winding should be connected in delta. This may either be the high-voltage winding or an additional winding (tertiary winding). Generally, these transformers are connected in delta-wye configuration.

Larger units may require three or more transformer windings to provide two or more medium voltages. Three-winding transformers may also be required to limit fault current to the medium-voltage system.

In most cases, three-phase transformers are used because they are more economical. The economy results from factors such as less space required due to one versus three transformers and lower unit cost due to reduced fire code requirements and bus work required. In some cases, single-phase transformers with wye connections on the high side are used to reduce the possibility of phase-to-phase or three-phase short circuits on the high-voltage winding of the transformer because this is essentially the same as a fault on the generator terminals. Also, this allows the use of a spare single-phase transformer, which may result in a reduction in the size of the station service transformer.

Transformers with wye-connected windings on the generator side are not usually grounded at this wye when unit-type generator connections are used because the generator neutral grounding is relied upon for the grounding of this portion of the system, and another ground at this location would interfere with the generator stator grounding system.

Because of the connections of the unit transformer and station service transformer, it may be necessary to use a nonstandard (high-voltage lags low-voltage by 30°) phase shift for the unit auxiliaries transformer to obtain proper phasing between the two sources.

9.6.7.3 Station Service (Startup) Transformer

This transformer is usually connected to a high-voltage system, and, for economic reasons (use of graded insulation), the high-voltage winding is usually connected wye and solidly grounded. The low-voltage winding is often connected wye to provide a circuit for ground-fault current on the medium-voltage system. To provide a source of ground current for a high-voltage system ground fault, a delta-connected winding is required, which may be a tertiary winding or the low-voltage winding if it does not require a wye connection.

Another connection used is a wye-wye transformer with no delta windings. The high-voltage wye is solidly grounded, and the medium-voltage wye is usually resistance grounded. In this case, a source of zero sequence from the station service transformer is not needed (even though it is available) because there is also a path for zero-sequence current

(adequate to operate medium-voltage system protective relaying) to flow from the highside source to the low-side ground fault.

There are many possible connections, but, in all cases, the phase relationship of the station service, unit auxiliaries, and unit transformer should be such that the system can be closed for a transfer.

It is not necessary to have the medium-voltage winding connected wye even if the medium-voltage system is required to be grounded. It could be connected zigzag or another transformer on the medium-voltage system could be used as a ground-current source. See Section 8.

It is possible to use a wye-wye-connected transformer with both wyes grounded. In this case, the high-voltage system zero-sequence network is the source of ground current for medium-voltage system faults. This impedance network should be reviewed to determine that it is adequate. Also requiring review are the conditions of faults on the high-voltage system at the station service transformer terminals and faults on the highvoltage system when the station service transformer is the only transformer at the station on the system. In addition, the use of a transformer without a delta winding may be the source of third harmonic currents and voltages.

Also see comments in 9.6.8.

The selection of a three-phase transformer for station service, as compared to three single-phase transformers with one spare, should be based on economics and reliability.

9.6.7.4 Substation (Load-Center) Transformers

These transformers are usually three-phase, for economic reasons, and are either delta-delta or delta-wye. Some low-voltage systems are operated ungrounded, and either connection may be used. Low-voltage systems that are grounded solidly or through an impedance usually use delta-wye with the wye on the low-voltage system. It is possible to use an alternate source of ground current, such as a grounding transformer, in parallel with delta-delta-delta transformers to provide grounding.

9.6.8 Impedance and Frequency

9.6.8.1 General

The transformer positive-sequence impedance, expressed in percent or per-unit, is used for short-circuit and voltage-regulation calculations. When specifying impedance values, the effect of tolerance should be considered. Transformers are specified normally to have minimum impedance consistent with circuit breaker interrupting ratings. In some cases, it is possible to purchase, at an additional price, transformers with a lower impedance tolerance range than is standard. In critical applications, this may be a more economical selection.

The zero-sequence impedance of the transformer is not usually equal to the positive-sequence impedance, and its value should be required in the specification if it is necessary for calculations.

9.6.8.2 Unit Auxiliaries Transformers

The positive-sequence impedance of the transformer should be specified along with the tolerance (see IEEE C57.12.00 [3] for impedance tolerance).

If the zero-sequence impedance is required for short-circuit calculations, it should be requested in the specification. In the case of solidly grounded systems, the effect of zero-sequence impedance should be considered in the application of switchgear to ensure that ground faults do not exceed the rating of the switchgear.

9.6.8.3 Station Service (Startup) Transformers

The positive sequence impedance should be specified along with the required tolerance.

The zero-sequence impedance should be required by the specification and, if it is critical, should be specified along with the required tolerance. It is desirable to have a zero-sequence impedance that effectively grounds the system when the transformer is faulted to ground on the high-voltage side and disconnected from the high-voltage system so that reduced insulation levels may be used on the high-voltage winding of the transformer. The effectiveness of the grounding of the high-voltage system in regard to insulation coordination should also be considered for the times when the station service transformer is the only system ground at the station.

Medium-voltage transformers with a grounded wye high-voltage winding and a resistance grounded wye low-voltage winding with no delta tertiary winding may be used at this location; and the effectiveness of the grounding and insulation coordination should be reviewed in relation to possible ground faults on the system.

9.6.8.4 Substation (Load Center) Transformers

The positive sequence impedance, along with tolerances, should be specified. The value of the zero-sequence impedance should be required in the specification.

9.6.8.5 Frequency

The frequency should be stated in the specification.

9.6.9 Terminal Facilities

9.6.9.1 General

The method by which each winding of the transformer will be connected to the system should be described in the specification.

9.6.9.2 Unit Auxiliaries Transformers

This transformer is usually connected to the generator isolated-phase bus on the high-voltage side. A flange for the phase enclosure connection should be specified. The low-voltage winding is usually connected to a bus (segregated phase, non-segregated phase, or cable). Flanges for bus enclosure connection should be specified.

If the unit auxiliaries transformer is connected to the high-voltage substation or system, the conditions will be the same as for the station service transformer as described in 9.6.9.3.

9.6.9.3 Station Service (Startup) Transformers

The high-voltage side is usually connected to a high-voltage system by overhead conductors. It may be desirable to specify the type of conductor clamps to be used. Corona-type fittings should be considered at 345 kV and above.

The low-voltage winding is usually connected to a bus (segregated, nonsegregated, or cable). Flanges for connecting the terminal compartment should be specified.

9.6.9.4 Substation (Load Center) Transformers

These transformers are usually supplied by cable or buses. The termination information should be given to the transformer manufacturer. In some cases, pad-mounted transformers that require no special provision for supply are used.

The low-voltage winding is usually connected to a switchgear bus. The transformer manufacturer and switchgear manufacturer (usually the same) coordinate this connection.

9.6.10 Surge Protection

9.6.10.1 General

Surge protection should be considered for all transformers. Direct lightning strokes are not a problem on the auxiliaries systems of power plants because most conductors are underground, protected in enclosures, inside the building, or shielded by other structures. However, voltage surges do occur due to traveling surges, switching surges, and some fault conditions, and protection for these conditions should be considered.

9.6.10.2 Unit Auxiliaries Transformers

These transformers are usually connected to the isolated-phase generator bus. Surge arresters are not usually applied to the high or low-voltage windings. As indicated in 9.6.6, the transformer insulation level is almost always higher than that of the bus or generator. Surge suppression devices on the high-voltage windings of the unit transformer usually provide acceptable protection. There may, however, be surge protection on the generator terminals, but it is questionable as to whether this provides any protection for the unit auxiliaries transformer.

If the transformer is connected to the high-voltage switching station, surge arresters should be used on the high-voltage busing terminals. (See discussion under 9.6.10.3 below.)

The BIL for the medium-voltage winding is generally standard for that voltage class, and usually no surge protection is used. Voltage surges from the high-voltage system are normally attenuated at this location.

9.6.10.3 Station Service (Startup) Transformer

The high-voltage winding is usually connected to the high-voltage switching station, and surge arresters are required at the transformer. The surge arresters are frequently purchased with the transformer and mounted on the transformer. They may, however, be purchased separately.

The low-voltage windings do not usually have surge protection on the basis that lightning surges that come through the transformer will be greatly reduced. However, the value of transferred surges should be evaluated to determine the need for secondary winding surge protection.

9.6.10.4 Substation (Load Center) Transformers

Transformers supplied by overhead lines require surge arresters for lightning protection. Dry-type transformers with reduced BIL ratings should be provided with surge arresters because of switching surges and, in some cases, surges due to ground fault conditions.

9.6.11 Short-Circuit Capability and Related Conditions

9.6.11.1 General

IEEE C57.12.00-1987 [3] describes standard mechanical force and thermal short-circuit requirements for transformers. Paragraph 7.1.3 defines the duration of the short-circuit current.

For transformers of 501 kVA and larger, the duration is 2 s, which is a reduction from the requirements of [3]. If a longer duration of the short-circuit current is required, or if system conditions are different, details must be specified. (See miscellaneous requirements below.) Unless the short-circuit source impedance is specified, the manufacturer will assume the values provided in the standard.

Unit auxiliaries transformers are subjected to more severe operating conditions than many other types of transformers. Many of these are related to short-circuit capability because they involve high currents that effect the transformer mechanically and thermally. Some of the conditions that should be considered are

- 1) High motor starting currents
- 2) High magnetizing voltages
- 3) Higher magnitudes and longer durations of short-circuit currents
- 4) Automatic transfer conditions
- 5) Phase relationships during transfer
- 6) Out-of-synchronism between the system and the motors

Generally, these conditions exist for unit auxiliaries transformers, and the specifications should address these conditions for adequate design of transformers.

9.6.11.2 Unit Auxiliaries Transformer

When large motors are supplied by the transformer, the manufacturer should be informed of starting conditions such as current magnitude, duration, and frequency of starting.

Upon sudden unit load loss, the voltage of the generator may rise considerably; and, if the regulator does not return it to a normal level quickly (or if the regulator is out of service), a high voltage will exist on the primary of this transformer. Other factors that may affect the voltage are the resonant and voltage multiplying effects of the capacitance of the system that is left connected upon loss of load that interact with the magnetizing impedance of the unit transformer.

A short circuit on the medium-voltage bushings of the unit auxiliaries transformer (or on the bus between the bushings and the transformer secondary breaker) will result in the highest short-circuit current through the transformer. (There are conditions of out-of-phase connections that may cause higher currents.) Protective relays will trip the unit for this condition.

When the generator substation breaker opens, and if there is no generator breaker, the load of the generator will be disconnected except for the short circuit that still exists. Upon loss of load, the generator voltage will increase (the amount of increase depends on prior conditions of the generator field). This can result in the short-circuit current through the transformer being as much as 20% to 30% above normal. The mechanical forces generated in the transformer windings will be at the highest value at the inception of the short circuit, when the short-circuit currents can be fully offset. The thermal conditions in the transformer will be affected by the current that exists from the inception of the short circuit until the current decays to the transformer rated current. This includes the higher value of current due to the increased generator terminal voltage. The transformer should be specified for the thermal and mechanical conditions that will exist during a fault of this type. An extension of this condition that should be considered is failure of the differential relay with unit fault clearing accomplished by a longer time backup relay or a bus fault with failure of the transformer low-side breaker.

The clearing time for short circuits on the medium-voltage bus that do not use differential relays is frequently long. The thermal and mechanical ability of the transformer should be considered for this condition.

In most cases, at least a small phase angle and magnitude difference in the voltages will exist across the open breaker when a manual closed transfer is made from the startup system to the unit auxiliaries system (and vice-versa). If the station service transformer is connected to the high-voltage system at a different point than the unit transformer, the phase angle and voltage magnitude difference may be substantial. This, of course, should be considered as part of the overall design. The conditions that will exist at the unit auxiliaries transformer terminals should be considered, and, if unusual, should be noted in the transformer specification.

Out-of-synchronism conditions should also be considered. If the operator disconnects the unit from the system, and then tries a closed transfer of the auxiliaries load to the station service system, an out-of-synchronism condition will

exist. The current during this condition may be higher than that for the maximum short-circuit design of the transformer. Protective relays may be used to block closing of the breaker for out-of-phase conditions. See Section 7.

An automatic transfer of the auxiliary system from the unit auxiliaries transformer to the station service transformer is usually made when a unit trip occurs. This may be a fast transfer (within about 6 to 8 cycles) or a delayed transfer after the motor residual voltage has decayed to an acceptable value (20% to 35% V). The condition that will exist during and after an automatic transfer should be considered, and any unusual condition should be pointed out in the specification.

9.6.11.3 Station Service (Startup) Transformer

As noted above, starting of large motors, transfer conditions, and out-of-synchronism conditions should be pointed out to the manufacturer, if they are expected.

9.6.11.4 Substation (Load Center) Transformers

Large motor starting currents and transfer conditions can occur for these transformers. Unusual conditions or conditions that are more severe than permitted by current standards should be noted.

9.6.12 Sound Level

9.6.12.1 General

The sound levels for large transformers should be considered both in the area of the transformer and at the site boundary.

NEMA TR-1-1980 [5] defines the sound requirements for most transformers. The NEMA TR-1-1980 [5] sound levels should be specified unless there are special requirements. If special requirements are necessary, they should be adequately described and specified.

9.6.12.2 Unit Auxiliaries Transformer

Generally, sound levels are within acceptable levels, but the sound level desired should be specified if it must be lower than the values given in NEMA TR-1-1980 [5].

9.6.12.3 Station Service (Startup) Transformers

Generally, sound levels are within acceptable levels, but the sound level desired should be specified if it must be lower than the values given in NEMA TR-1-1980 [5].

9.6.12.4 Substation (Load Center) Transformer

Generally, sound levels are within acceptable levels, but the sound level desired should be specified if it must be lower than the values given in NEMA TR-1-1980 [5].

9.6.13 Evaluation of Losses

9.6.13.1 General

Large transformers are custom designed, and certain parameters may be selected to reduce losses. However, reduction of losses may increase manufacturing costs. Therefore, to purchase the most economical transformer, there should be an evaluation of total cost based on first cost and evaluated losses. If the transformer manufacturer is to make the most economical design, the values that will be used should be in the specification. These loss evaluation figures should be for no-load losses, load losses, and motor loads for the fans and pumps. The values depend on estimated use of the

transformer during the years of service of the unit, the load cycles during use, and other things such as cost of money and cost of plant.

If a manufacturer will be penalized for exceeding the guaranteed losses, the specification should state the method that will be used.

9.6.14 Accessories and Protective Devices

9.6.14.1 General

The following is a list, with comments, of additional equipment that may be required on transformers. See [2] and [B1].

- 1) *Current transformers and linear couples.* The specification should be coordinated with relaying and metering requirements. The overall ratio and taps desired should be specified, along with the relaying accuracy class (example C800) of current transformers.
If the current transformer will be used for metering, the metering accuracy class, along with the burden at which this will exist, should be specified (example 0.3B10). Refer to IEEE C57.13-1978 [4] for ratios and accuracy. Linear couples are used usually as part of a relaying system that uses other linear couplers. The designer of the linear coupler system should provide information for the specification of this equipment.
- 2) *Potential devices.* Transformers such as the station service transformer or the unit transformer connected to the high-voltage system station may require a potential device. The specification of this equipment is outside of the scope of this discussion.
- 3) *Surge arresters.* This equipment is frequently purchased with the transformers, and the locations at which it is required have been discussed. The actual specification for the surge arresters is outside the scope of this discussion.
- 4) *Magnetic liquid level gauge.* This is provided as a standard device and is mounted on the side of the transformer tank. It may be specified with or without alarm contacts.
- 5) *Dial type oil thermometer.* This equipment is provided as a standard accessory on the transformer and is mounted on the side of the transformer tank. This equipment may be specified with or without alarm contacts.
- 6) *Valve to serve as drain valve, bottom filter-press connection, and liquid sampling valve.* This equipment is provided as a standard accessory on the transformer, but it should be specified in order to obtain desired sizes for filter press connection. The standard valve is 2 in for transformers rated above 2500 kVA, and has a 3/8 in sampling device.
- 7) *Valve on top for filter press connection.* This equipment is provided as a standard item on the transformer, but it should be specified to obtain desired size for filter press connection. The standard valve is a 1 in globe type.
- 8) *Tank grounding provision.* Provisions are made as standard practice for grounding the transformer tank. The standard is to provide two ground pads near the tank bottom, located at diagonally opposite corners. If special equipment is required, it should be stated in the specification.
- 9) *Pressure-vacuum gauge equipment.* This equipment is supplied normally as a standard item on transformers rated 2500 kVA or above, or on transformers rated 200 kV BIL or above when they are of sealed tank or gas-oil seal construction.
- 10) *Manholes or hand holes on cover.* These features are supplied generally as standard items. In some cases, the hand holes may be welded on. If manholes, removable hand holes, or hand holes that are larger than normal are required, they should be specified.
- 11) *Cover mounted mechanical pressure relief device.* This device is supplied normally as a standard feature. It may be specified with or without alarm contacts.
- 12) *Nameplates.* The nameplate is provided as a standard item with standard information as defined in IEEE C57.12.00-1989 [3]. If additional information is to be listed, it should be specified.
- 13) *Lifting hooks on tank, lifting eyes on cover, and provisions for jacking.* Normally, these will be provided as standard mechanical features of the transformer. If special provisions are required, they should be specified.
- 14) *Protective relays.* Sudden-pressure relays for internal fault indication, pressure relays, or the manufacturer's standard protective relays can be provided on liquid-filled transformers, if specified.
- 15) *Combustible gas detection relay.* This type of device can be obtained with or without a recorder.

- 16) *Annunciators.* Annunciators and provisions for remote alarms can be provided in the control box on the transformer. The number and the type of alarms required should be specified.
- 17) *Elapsed time meter.* A device of this type can be obtained, if specified.
- 18) *Provision for future forced-air cooling.* Provisions may be obtained, in some cases, so that transformers can be upgraded in the future.
- 19) *Dial type winding temperature indicator.* A device that uses both oil temperature and load current is calibrated to indirectly indicate the hot-spot temperature of the transformer. It can be specified with three or four contacts that can be used for starting cooling equipment, alarm, or trip functions.
- 20) *Automatic control for auxiliary cooling.* A control scheme can be obtained using the device in (19) above to automatically turn on cooling fans and pumps. It is also possible, with some fan/pump combinations, to have an automatic throwover scheme for the fans and pumps or, a selector switch may be specified to select which of two cooler groups operates first. Provisions for redundant power supplies to transformer control box (with automatic transfer from one to the other) should be specified, if desired.
- 21) *Oil-flow indicators.* Manufacturers will provide oil-flow indicators if they are specified. They are a standard feature for oil and air (FOA) cooling.
- 22) *Remote winding or oil temperature detector.* A 10 Ω , 25 °C device of this type may be obtained for connection to remotely located temperature indicators. These will be provided by the transformer manufacturer only if specified.
- 23) *Deenergized tap-changer control handle with locking pin.* This may be a standard item. It should be specified if it is desirable to have the control handle at ground level.
- 24) *OSHA fan guards.* Transformers will probably have OSHA approved fan guards. However, this should be a part of the specification.
- 25) *Neutral grounding transformer and resistor.* In some cases, this equipment is purchased with the transformer and may be mounted on the transformer.
- 26) *Oil preservation system.* In general, three systems are available: sealed-tank system, positive inert gas system, and oil conservator system. Variations of all systems exist. The usual system in the US is sealed tank or positive pressure inert gas system for unit auxiliaries transformers that are directly connected to the generator bus. The preferred system should be specified.

9.6.15 Tests

9.6.15.1 General

To help ensure that a transformer meets the specification and will withstand the conditions it will be exposed to in service, tests are performed in the manufacturer's plant before the transformer is shipped. Certain tests will be performed whether required by the specification or not. It is better to specify all tests required so that there is a definite agreement with the manufacturer. (See [3], [B8], and [B12].)

Routine tests are

- 1) Resistance measurement of all windings at rated voltage tap and tap extremes of the first unit built on a new design
- 2) Ratio tests of all tap positions
- 3) Polarity and phase relation test
- 4) Excitation loss and current at rated voltage and frequency
- 5) Impedance and load loss at rated current and rated voltage tap and at tap extremes of each design type
- 6) Temperature tests on one unit of a new design (double secondary transformers should have temperature test on each secondary)
- 7) Low frequency applied potential test and induced potential test

Optional tests are

- 1) Sound level tests
- 2) Impulse tests

- 3) Switching surge tests
- 4) Front-of-wave tests
- 5) Short-circuit tests
- 6) Corona or partial discharge tests

9.6.15.2 Unit Auxiliaries Transformers

The standards should be reviewed both for the routine tests that will be performed and for optional tests. Those tests that are desired should be specified. Only one of several identical transformers will routinely be given a temperature rise test, and it should be decided whether this is satisfactory. Also, the amount of dielectric testing required should be decided and specified.

9.6.15.3 Station Service Transformers

These transformers are usually connected to high-voltage or extra-high-voltage substations, and dielectric testing should be given a thorough review. In general, impulse tests and partial discharge tests should be specified, and, depending on the high voltage rating, switching surge tests should also be considered.

9.6.15.4 Substation (Load Center) Transformers

Manufacturer's tests for these transformers are usually standard. They should be reviewed, and any additional requirements should be added. These transformers usually are small and not unusual, and therefore do not require extensive testing.

9.6.15.5 Test Reports and Data

The manufacturer is required by standards to provide test reports. Any additional information required should be specified. Whether some or all tests will be witnessed by an engineer should also be specified in specification.

9.6.16 Tank and Foundation Requirements

9.6.16.1 General

ANSI C57.12.10-1987 [1] defines the requirements for pressure and vacuum conditions. Unusual conditions should be specified.

Lifting, moving, and jacking facilities are also defined in [1]. The manufacturer should be informed of the type of foundation to be used, for example, slab, piers, axial (with wheels), or others.

9.6.17 Shipping Requirements

9.6.17.1 General

Damage during shipment is a frequent problem with transformers. In many cases, specifications require shock recorders to be mounted during shipment. The disposition and the analysis of this information should be defined in the specification, along with the acceptable limits and responsibility. If a certain mode of transportation is required, it should be stated.

9.7 Voltage Regulation

9.7.1 General

Experience has indicated that load tap changers decrease the reliability and availability of a transformer. Therefore, they are not usually specified for generating station auxiliary service transformers. The selection of rated voltages, taps, and impedance will depend on the acceptable ranges of the supply voltage and the service buses.

9.7.2 Voltage Range of Medium-Voltage Bus

Although it is desirable to hold a constant voltage on the medium-voltage bus, it is reasonable for the voltage to vary, due to changes such as the generator voltage or high-voltage system voltage, up to 105% of the transformer secondary voltage rating and down to 95% of the motor voltage rating (approximately +10% and -5% of motor voltage rating). In this range, all equipment on the medium-voltage bus should operate satisfactorily under continuous service conditions. Modest excursions beyond these values are acceptable for short periods.

Standard motors will operate satisfactorily at $\pm 10\%$ of motor rated voltage at their terminals. This is usually the limiting condition. However, if the voltage is down to -10% at the medium-voltage motor terminals (the medium-voltage bus voltage will usually be approximately the same), this voltage may be reflected into the low-voltage system and adequate voltage on that system should be confirmed. If the variation in the medium-voltage system is greater than $\pm 10\%$, a detailed analysis of the capability of each individual load must be performed to verify the acceptability of the voltage variation.

When two different medium voltages are obtained from three winding auxiliaries transformers, the voltage regulation on the two medium-voltage buses will usually be different. This condition should be reviewed.

9.7.3 Voltage Range of Low-Voltage Bus

The low-voltage bus voltage range should also be considered. The low-voltage bus should not operate, except for transient periods, above 110% or below 95% of the motor voltage ratings. This allows 5% voltage regulation between the bus and motor terminals. As mentioned above, the critical voltage is $\pm 10\%$ of motor voltage at the motor terminals.

9.7.4 Voltage Range of Generators

When the unit auxiliaries transformer is connected to the generator bus, the primary bus voltage varies with the generator terminal voltage. The standard range of terminal voltage for a generator is from 95% to 105% of rating. In addition, a generator may be operated lower than 95% if the generator is derated and the manufacturer is in agreement. If the primary voltage of the unit auxiliaries transformer is varying through a range of 10% or more, the secondary will also vary similarly in addition to the load-voltage regulation considered in the paragraph below.

9.7.5 Voltage Regulation of Unit Auxiliaries Transformers

When the unit auxiliaries transformer is unloaded, there is no voltage reduction through it except that due to the turns ratio. When the transformer is loaded, it has a voltage reduction due to the flow of current through its impedance. The amount of voltage regulation is a function of the impedance of the transformer and the magnitude and power factor of the load. Values at full load should be calculated for each particular installation and load condition.

9.7.6 Total Voltage Regulation Consideration

The variation of the medium-bus voltage is affected by the variation in the source voltage and the voltage reduction through the unit auxiliaries transformer. It is not unusual to have a variation range of 15%.

There is also a voltage reduction between the medium and low-voltage buses due to the impedance and load of the substation transformer, which may be approximately 5%. Since the low voltage will vary as the medium voltage

varies, and since there is an additional reduction due to the substation transformer, the low-voltage system may be the worst case condition.

In some cases, the unit auxiliaries transformer taps may be set low to provide a maximum voltage up to 107.5% of the transformer low-voltage rating during no load (when the medium-voltage bus is not connected). This will not damage the transformer because it is designed to withstand 110% voltage at no load. When the medium-voltage bus is connected to the transformer, it will usually have some load on it. This may be enough to provide a voltage reduction to 105% of transformer rated secondary voltage, which should be satisfactory for the motors.

If the expected voltage changes are too great to be handled by fixed taps, it may be necessary to specify a unit auxiliaries transformer with a load-tap-changer (LTC). This, however, may effect the reliability of the transformer.

Some stations may not have a voltage regulation problem in the immediate future, however, consideration should be given during the design phase to the expected future changes in system operation that may result in voltage problems.

9.7.7 Transient Voltage Regulation due to Motor Starting

Large motor starting currents at rated voltage are usually about five to seven times full load current. This current is highly reactive, so that the power factor is approximately 20% to 40%. This reactive power flow causes a voltage reduction through the reactance of the unit auxiliaries transformer and the impedance of motor cables. This reduced voltage exists for only the short period while the motor is coming up to speed, but it does reduce the voltage at the motor terminals and increases the motor starting ability requirements.

The starting current of the motor is reduced approximately in direct proportion to the reduction in voltage at the motor terminals.

The reduction in voltage due to motor starting current should be considered, in addition to the reduction due to source voltage variation and load, and the motor should be specified for starting during the worst condition. Also, the lowest voltage that will exist should be above that required for contactors, relays, etc. that may operate incorrectly or unsuccessfully at reduced voltage.

Usually, plant operation can tolerate, by design, this reduced voltage during starting of large motors in order to obtain a more economically designed plant. Voltage dips in the plant usually do not affect customers outside the plant.

The design of the plant should consider the ability of the motors, contactors, relays, etc. to start for the worst system conditions that may exist and should define the criteria necessary for startup.

9.7.8 Methods for Improvement

The short-circuit rating of the switchgear on a bus usually limits the amount of short-circuit current that can be allowed. This short-circuit current is supplied from the motors and the auxiliaries transformer and, therefore, establishes the lower limit for the impedance of the transformer.

One method that may help the voltage regulation conditions is to reduce the impedance of the transformers. If the amount of short-circuit contribution from motors can be reduced, a larger amount can be allowed through the transformer for a given rating of switchgear. This, in effect, allows a reduction in transformer impedance and, consequently, less voltage regulation.

Another method that applies when short-circuit currents from motors are being supplied from another bus through the transformer is to increase the impedance between the two buses; then, the impedance between the bus in question and the high voltage can be decreased. A similar condition can be improved by a duplex reactor for conditions in which two buses are connected together on the medium-voltage side of the transformer. The duplex reactor provides a high impedance between the two buses during a short-circuit condition.

Another solution is the use of switchgear with higher interrupting capability on the medium-voltage bus, but this results in higher costs.

Another method is the use of an LTC unit auxiliary transformer, but this increases the price and decreases the reliability of the transformer.

9.8 Bibliography

[B1] ANSI C57.12.22-1989, American National Standard Requirements for Transformers — Pad-Mounted Compartmental-Type, Self-Cooled, Three-Phase Distribution Transformers with High-Voltage Bushings, 2500 kVA and Smaller: High-Voltage, 34 500 GrdY/19 920 V and Below; Low-Voltage 480 V and Below.

[B2] ANSI C57.12.70-1978 (Reaf 1987), American National Standard for Terminal Markings and Connections for Distribution and Power Transformers.

[B3] IEEE C37.20.1-1987, IEEE Standard for Metal-Enclosed Low-Voltage Power Circuit Breaker Switchgear (ANSI).

[B4] IEEE C37.20.2-1987, IEEE Standard for Metal-Clad and Station-Type Cubicle Switchgear (ANSI).

[B5] IEEE C37.20.3-1987, IEEE Standard for Metal-Enclosed Interrupter Switchgear (ANSI).

[B6] IEEE C57.12.01-1989, IEEE Standard General Requirements for Dry Type Distribution and Power Transformers Including Those With Solid Cast and/or Resin-Encapsulated Windings.

[B7] IEEE C57.12.80-1978 (Real 1986), IEEE Standard Terminology for Power and Distribution Transformers (ANSI).

[B8] IEEE C57.12.90-1987, IEEE Standard Test Code for Liquid-Immersed Distribution, Power, and Regulating Transformers; and Guide for Short-Circuit Testing of Distribution and Power Transformers (ANSI).

[B9] IEEE C57.92-1981 (Reaf 1991), IEEE Guide for Loading Mineral-Oil-Immersed Distribution and Power Transformers up to and Including 100 MVA with 55 °C or 65 °C Winding Rise (ANSI).

[B10] IEEE C57.94-1982 (Reaf 1987), IEEE Recommended Practice for Installation, Application, Operation, and Maintenance of Dry-Type General Purpose Distribution and Power Transformers (ANSI).

[B11] IEEE C57.96-1989, IEEE Guide for Loading Dry-Type Distribution and Power Transformers (ANSI).

[B12] IEEE C57.98-1986, IEEE Guide for Transformer Impulse Tests (ANSI).

[B13] IEEE C57.100-1986, IEEE Standard Test Procedure for Thermal Evaluation of Oil-Immersed Distribution Transformers (ANSI).

[B14] IEEE C57.104-1978 (Reaf 1987), IEEE Guide for the Detection and Determination of Generated Gases in Oil-Immersed Transformers and Their Relation to the Serviceability of the Equipment.

[B15] IEEE C57.106-1977, IEEE Guide for Acceptance and Maintenance of Insulating Oil in Equipment.

10. Equipment Used for Load Switching and Fault Isolation

10.1 Introduction

This section provides a guide for integration and application of switchgear, combination starter panels, and panelboards to accomplish load switching and fault isolation.

Generating station service system feeders supply buses that supply other feeders or a single designated load, such as a motor or transformer. When feeders supply large loads, it may be more applicable to use a fault interrupting circuit breaker as the load controller. A high frequency of operation, however, may require the use of contactors for medium as well as low-voltage motor loads. When feeders supply smaller loads, load switching and fault isolation are usually provided by separate devices.

The number, capacity, and independence of power supply feeders to load service buses directly affects the availability of utilization devices or their functions. There are alternatives in the selection of equipment in each voltage level that may affect availability of the generating unit.

Traditionally, the electrical auxiliaries systems of a power generating system are radial type distribution systems with the ability to interconnect some buses to provide some backup power supply. Sources are usually not paralleled in order to limit fault duty on equipment.

10.2 References

- [1] ANSI C37.06-1987, American National Standard for Preferred Ratings and Related Required Capabilities for AC High-Voltage Circuit Breakers Rated on Symmetrical Current Basis.¹⁰
- [2] ANSI/NFPA 70-1990, National Electrical Code.¹¹
- [3] IEEE Std 80-1986 (Reaf 1991), IEEE Guide for Safety in AC Substation Grounding (ANSI).¹²
- [4] IEEE Std 241-1990, IEEE Recommended Practice for Electric Power Systems in Commercial Buildings (ANSI).
- [5] NEMA ICS 2-1988, Industrial Control Devices, Controllers, and Assemblies.¹³
- [6] NEMA PB1.1-1986, General Instructions for Proper Installation, Operation, and Maintenance of Panelboards Rated 600 Volts or Less.

10.3 Switchgear

10.3.1 Circuit Arrangements

The power-supply feeders for distribution systems may be radial, dual-supply, low-voltage selective or dual-supply, high-voltage selective, i.e., selection takes place at a higher voltage than that of the bus being supplied. (See 2.3.3 of IEEE 141-1986, [B21]¹⁴.) Considerations that affect the design are safety, reliability, simplicity of operation, voltage

¹⁰ANSI publications are available from the Sales Department, American National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036, USA.

¹¹NFPA publications are available from Publications Sales, National Fire Protection Association, 1 Batterymarch Park, P.O. Box 9101, Quincy, MA 02269-9101, USA.

¹²IEEE publications are available from the Institute of Electrical and Electronics Engineers, Service Center, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA.

¹³NEMA publications are available from the National Electrical Manufacturers Association, 2101 L Street NW, Washington, DC 20037, USA.

¹⁴The numbers in brackets, when preceded by the letter "B," correspond to the Bibliography in 10.12.

regulation, maintenance, and flexibility. Refer to Section 3. for further information on system philosophy and single-line diagrams.

Metal-clad switchgear is usually applied at the medium-voltage level (1001-15 000 V) because the critical nature of the loads served requires high integrity with circuit switching flexibility and circuit protection. The medium-voltage switchgear in a power plant is usually dual supply low voltage selective. In some cases, dual supply high-voltage selective systems have been utilized. Where two medium-voltage levels are used within the power plant, it is sometimes beneficial to have the lower voltage as a radial system. Refer to 10.4.2 for further explanation of the respective distribution systems. In selecting switchgear, the required interrupting rating is determined by the duty cycle and maximum short-circuit current available during fault conditions on the switchgear load feeders. See ANSI C37 . 06-1987 [1]¹⁵.

Switchgear applied at the medium-voltage level may have different configurations due to system constraints and preferences in system operation. This discussion is limited to commonly used power plant medium-voltage electrical systems.

Refer to Fig 10.1 for a typical single-line diagram of the medium-voltage electrical system in a fossil power plant.

10.3.1.1 Types of Incoming Feeders and Bus Ties

Incoming feeds and bus ties to medium-voltage switchgear may be single-conductor or three-conductor cables or nonsegregated phase bus duct. When using single-conductor cable, the impedance is higher than for three conductor cable if the single conductors are laid with a maintained spacing. Each application has its own requirements, but the higher voltages (13.8 kV and 6.9 kV) tend to be nonsegregated phase bus, and the lower voltages (4160 V and 2400 V) tend to be cable or cable bus. However, high currents at 4160 V and 2400 V and the spacing requirements may dictate the use of nonsegregated phase bus. The circuit between the unit service transformer and the metal-clad switchgear should be as reliable as the circuit between the generator and the step-up transformer connected to it. The cost impact of minimizing the length of the switchgear feeder cable or bus versus minimizing the total length of the cables to the individual loads fed from the switchgear must be analyzed. In general, the closer the switchgear is to the center of the area served, the shorter the cable runs. To improve reliability, the switchgear is often placed in its own dry, ventilated room, with access limited to authorized power plant electrical personnel, and the incoming feeder-breaker compartments are located at opposite ends of the switchgear lineup.

¹⁵The numbers in brackets correspond to those of the references in 10.2.

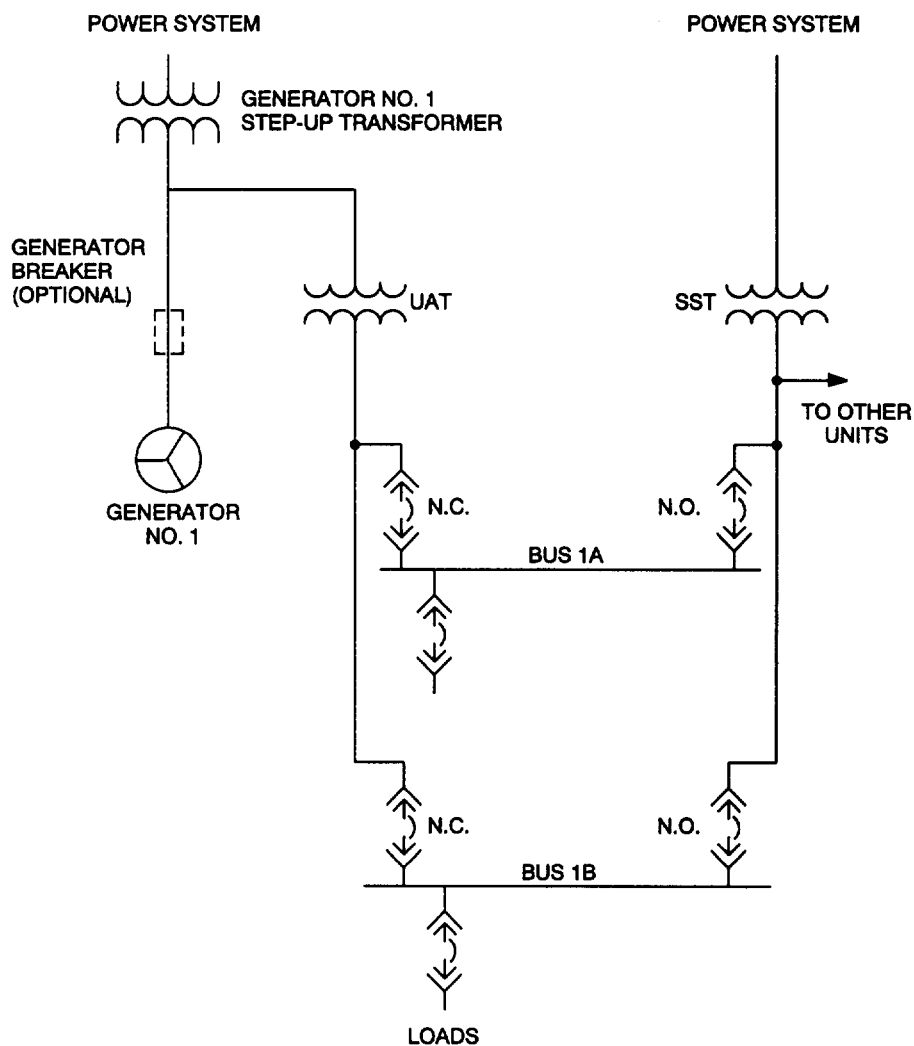


Figure 10.1 — Typical Nonnuclear Generating Unit Medium Voltage Electrical System

10.3.2 Load Grouping

As shown in Fig 10.1, there are usually two or more separate switchgear assemblies, typically one for each mechanical load division. However, auxiliary load, reliability, operating flexibility, etc., often dictate that more buses are required. In general, the unit loads are grouped in such a manner that if one medium-voltage bus is out of service for maintenance or other reasons, the unit could still be operated from 50% to 100% capacity. Unit service transformers may have two windings, as shown, or three windings to provide two different auxiliary voltages and/or output, MVA or to limit motor contribution to a fault on a bus or feeder.

10.3.3 Future Loads

During the initial system design, it is prudent to allow 25% capacity for increase in loads and short-circuit contributions from unit auxiliaries until they become finalized. It is desirable to have a 10% to 25% reserve capacity (both load and short circuit) on a bus for future expansions. The relationships between bus voltage regulation, short-circuit interrupting capacity, motor-starting voltage, and transformer impedance are covered in other sections.

10.3.4 Motor Sizes

The optimum selection of power supply voltage to motors is based on technical and economic considerations. The technical considerations include the ability of the power supply system to maintain voltage during normal operating and motor starting conditions within the motor design limits. The economic considerations include tradeoffs between the motor costs for different voltages and the costs of switchgear, unit auxiliary, and station service transformers associated with the selected voltage. The appropriate voltage for power supply to motors is variable because the physical size of the motor is determined by the revolutions per minute, the size of conductors required for the starting current, and the amount of insulation required for the voltage level. The impedance of the power-supply circuit and its voltage regulation are also important factors. Table 10.1 lists typical horsepower ranges for motors of various nameplate voltage ratings.

10.3.5 Controls and Interlocks

A 125 V dc stored energy (battery) source of power, which is immune to a loss of ac power, is used typically for critical control functions to permit circuit breaker operation when there has been a failure of the ac system. This allows the switchgear to be tripped and reenergized so as to prevent damage to the motors and loads fed from the medium-voltage bus, and to prevent damage to the medium-voltage switchgear and the transformer feeding it. Other voltages, 48 V dc or 250 V dc, may also be used.

Latched circuit breakers and/or contactors are required to provide for continuous power supply during and following low-voltage transients on the power system caused by system faults and lightning surges. Protective relays and interlocks may be provided so that when the bus voltage is degraded to a value (typically 80% or less of rated voltage) below which it is possible to start a motor without causing a running load to stall, the bus source will be tripped. When transfer capability is provided, a transfer blocking scheme may be provided to prevent transfer to an alternate source during transients, such as when a fault appears on the bus or when the alternate source is out of phase or has low voltage. Bus overcurrent and time delayed ground overcurrent relays are also provided for the protection of the switchgear.

Table 10.1 — Nameplate Voltage Ratings of Standard and Nonstandard Three Phase Induction Motors and Their Horsepower Ranges as Offered by Motor Manufacturers

Nominal System Voltage	Nameplate Voltage	Standard Horsepower	Nonstandard* Horsepower Range	Horsepower Rating Range
2400	2300	100–2500	2501–20000	200–4000
4160	4000	200–10000	126–249 10 001–45 000	400–7000
4800	4600	250–15000	126–249 15 001–45 000	(nonstandard motor voltage)
6900	6600	500–15 000	350–499	1000–12 000
13 800	13 200	See note [†]	15 001–45 000	3500–25 000

*Information available from manufacturer.

[†]A practical 13200 V motor that utilizes the stator slot area effectively is about a minimum of 3000 hp. A small hp motor may have 10% conductor and 90% insulation in the slot area, which is impractical. It would not provide sufficient strength for the winding.

Breakers used for synchronization and fast automatic bus transfers should be of the fast closing type (5–7 cycles). If a fast automatic bus transfer cannot be completed within a few cycles or before a significant phase shift occurs between bus residual voltage and the new source, then the transfer should be delayed until bus residual voltage decays to 25%

or less of rated voltage. This should eliminate any excessive shock or stress to motors when the bus is reenergized. It is more demanding on the system, however, because of the inrush current of many motors.

This scheme also requires coordination of the controls of devices that would be deenergized during this slow transfer. Their deenergization should not cause tripping of loads that are needed after transfer. The deenergized devices may need to be automatically reenergized.

A high-speed, power transfer relay may also be considered to synchronously transfer the load to the new source.

Electrical interlocks are provided as required for the correct normal operation of motor and other load feeder breakers. Additional electrical logic circuits are added to protect the switchgear bus and to disconnect faulted feeders through the use of various relay schemes. Additional relays are used to protect the motors, and additional permissive contacts are used as interlocks to control breaker operation. For example, a pump motor may not be started unless the oil pressure to the pump bearings is adequate.

Mechanical interlocks prevent exposure of personnel to safety hazards. For example, the door to the breaker compartment may not be opened unless the breaker has been tripped. After the breaker has been tripped, it may then be withdrawn, so that the current is not interrupted by the primary disconnects.

10.3.6 Duty

The useful life of a switchgear assembly will depend on its operating temperature and other ambient conditions. The standard continuous and fault interrupting ratings have been selected for a long life (greater than 30 years). They are based on a clean environment, free of chemical contaminants, with no vibration, and with ambient temperatures not exceeding 40 °C. It is also expected that periodic inspection and maintenance will be performed to ensure that mechanical components are working properly and temperature rises are not exceeded.

10.3.6.1 Load Duty

When rated operating temperatures are exceeded, the rate of oxidation and resistance of electrical connections and contacts will increase. Also, the life of solid organic insulations will be reduced, i.e., they will age faster. When ambient temperatures exceed 40 °C for long periods, the full-load rating of the switchgear should be reduced. Forced ventilation may be considered in some installations to reduce the temperature inside the enclosure. (Most switchgear components are rated for a temperature inside the enclosure from 45° to 55 °C.)

The temperature rise is a function of the load current and the heat-removal rate. The following formula is recommended by IEEE C37.010-1979 [B11] for derating the current rating of switchgear components when ambient temperatures are greater than 40 °C.

$$I_t = I_R \cdot \frac{T_M - t^{1/1.8}}{T_M - 40}$$

I_t = continuous rating at ambient t
 T_M = maximum temperature rating for switchgear, in °C
 t = expected ambient temperature, in °C

10.3.6.2 Fault Duty

The standard fault interrupting tests for circuit breakers are considerably more severe than the actual operating condition for generating station service systems. The standard requires that rated temperature rises shall not be exceeded after a close-open 15 s delay close-open operation at rated fault conditions. This is required for breakers on residential and feeder circuits that must be reclosed and remain in service following the removal of the fault. However, in generating stations, maximum faults are of a permanent nature. Therefore, no automatic reclosure is used, and the circuit breaker can usually be removed for inspection and maintenance before it is returned to service.

10.3.7 Materials

The materials specified for switchgear assemblies have a significant effect on rating and reliability.

10.3.7.1 Conductors

The standard hot spot temperatures are limited for the following types of connections:

Connection	Allowable Temperature, °C
Copper to copper	70
Silver to silver	105
Cables copper to copper	70
Cables silver to silver	85

Standard platings used are silver plating, tin plating, or equivalent.

10.3.8 Motor Controllers

Medium-voltage motor controllers (starters) are used to control and protect frequently switched squirrel-cage, wound-rotor, and synchronous motors, and are optional for others. They can also be used to feed transformers and other power utilization circuits. The 400 A unfused contactors have an interrupting rating of 50 MVA. The 700 A unfused contactors have an interrupting rating of 75 MVA. (See NEMA ICS 2-1988 [5]).

NEMA Class E2 controllers incorporate the high-interrupting capacity of fast acting fuses. These current-limiting fuses both protect the connected equipment and control against high short-circuit current.

In addition to normal motor protective relays, NEMA Class E1 controllers include instantaneous overcurrent relays to signal the contactor to open on fault current. They may be employed on systems having available short-circuit currents up to the interrupting rating of the contactor.

Relaying, metering, ground-fault protection, and lightning arresters are typical of available options.

Motor controllers are designed primarily for the control requirements of motors applied to distribution systems rated 2400 V, 4160 V, or 4800 V. 7200 V starters are available in limited applications. Motor controllers are available in the following types: full voltage or reduced voltage (resistor, reactor, and autotransformer), nonreversing or reversing, dynamic braking, and multispeed.

10.3.8.1 General

Starters may be stacked two or three high, where horsepower rating and need for metering and relaying is limited to allow such stacking. Nonstack design (one high) is used normally for synchronous motor starters, wound-rotor starters, and squirrel-cage induction starters that have a considerable number of extra control functions, protective relays, and/or metering associated with them. All enclosures have the same bus height and may be connected together by bus splicing plates.

With one common drawout contactor, 400 A starters are available in either one, two, or three high construction.

700 A starters are available in one high construction only.

10.3.8.2 Mounting

Medium-voltage starters are available in either back-to-back (60 in deep) or back-to-wall (30 in deep) mounting, letting the control lineups be arranged to suit floor space and application requirements. Maximum height is 90 in, and cubicle width varies from 34 to 44 in.

10.3.8.3 Drawout Contactors

The air-break contactor that is normally furnished is of the magnetically held in type. It is drawout and fully rated at 400 or 700 A (8 h open rating) in accordance with NEMA and UL standards (see 10.2 and 10.12).

The standard contactors for industrial motor starters are closed by a single magnet and are held closed by the same magnet. This contributes to simplicity of mechanical design and increases the mechanical life of the contactor.

Such a contactor may not need mechanical repair before one million operations, and this long mechanical life is due largely to mechanical simplicity and ruggedness.

Low voltage on the contactor operating coil of an electrically held contactor will cause the contactor to open. For most motor applications, it is desirable to disconnect the motor from the line when the system voltage is lost or lowered appreciably. Therefore, the electrically held contactor is appropriate.

The operating voltage for the contactor coils is 230 V ac, 115 V ac, 48 V dc, 125 V dc, or 250 V dc, as required.

For all NEMA Class E1 starters, the contactor must be capable of interrupting the short-circuit current available. On these applications, instantaneous overcurrent relays are used to interrupt the contactor ac coil circuit.

There are some applications in which it is not safe or desirable to disconnect the motor from the line during voltage depression. These applications are those generally associated with a critical drive in which the continued rotation of the drive may be more important than possible damage to the motor from low voltage. The mechanical latch maintains contactor closure under the most severe undervoltage conditions, including complete loss of voltage. Latch may be specified with ac or dc latch and trip coils and also with manual trip, if desired.

Mechanical latch mechanisms have a life expectancy of about 50 000 operations. While this is only a fraction of the one million operations expected of the nonlatched form, it still permits 10 starts per day for almost 20 years before repair, and greatly exceeds the life of circuit breakers.

10.3.8.4 Fuses

To protect the motor branch circuit against the damaging effects of short circuits, current-limiting power fuses may be used in motor controllers (starters). Current-limiting power fuses interrupt all overcurrents of a magnitude greater than that intended for contactor interruption. On full fault, these fuses start limiting current within the first 1/4 c and interrupt within the first 1/2 c. Because they are fast acting, these fuses are coordinated easily with system protective relaying to give selectivity in short-circuit protection.

These fuses usually are front mounted on the contactor so that they can be easily inspected, removed, and replaced.

A design feature of motor starting fuses inherently limits recovery voltage to safe values. The insulation in the control circuit is thus safeguarded.

Controller fuses must have sufficient capacity to carry starting and full-load currents, yet they must interrupt locked rotor currents of motors at a desirable low value. They are therefore made in a number of ratings or sizes so that maximum protection can be obtained over a range of motor horsepowers.

10.4 Secondary Unit Substations

10.4.1 General

Secondary unit substation transformers supply load buses that may be radial, dual supply low-voltage selective, or dual supply high-voltage selective. Service selection is based upon the requirements for safety and availability following the failure of a single power-supply-circuit component.

Unit substations of a standard design are available for these alternative service connections. They consist of incoming line, transformer, and switchgear sections (assemblies), all electrically and mechanically connected together in a coordinated design. Diagrams of these substations appear in Fig 10.2.

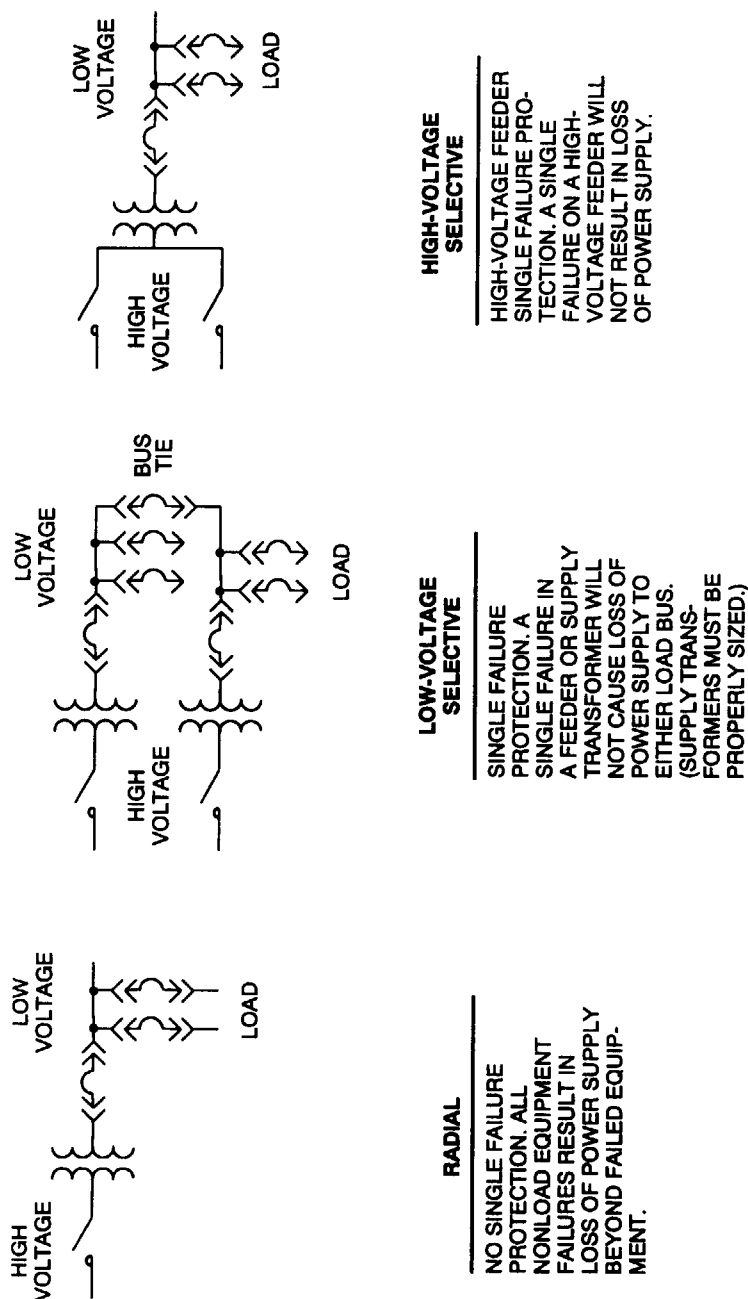


Figure 10.2 – Standard Configuration

Standard low-voltage metal-enclosed switchgear in dead-front switchgear assemblies is available for service up to 1000 V ac and up to 3200 V dc. These assemblies contain air circuit breakers, buses, and connections with an enclosure on the ends, back, and top. Air circuit breakers are contained in individual compartments and may be electrically controlled remotely, from the front panel, or both. They may also be of the manual type.

There are two types of low-voltage metal enclosed switchgear assemblies. Stationary type assemblies contain air circuit breakers that are rigidly mounted and have no special arrangement for quick removal from the housing. Drawout types contain air circuit breakers arranged so that they may be easily disconnected and withdrawn from the housing. Primary power molded-case circuit breakers are used only in switchgear with stationary air circuit breakers

and are not used, in general, in switchgear with drawout type air circuit breakers. The term distribution switchboard is used for assemblies with stationary type circuit breakers and low-voltage switchgear for assemblies with drawout type circuit breakers.

10.4.2 Standard Configurations

Radial systems with standby ties have the incoming high-voltage feeder and both high and low-voltage interrupting devices adjacent to the transformer. The bus tie is usually located in the center of the switchgear lineup for the low-voltage selective system. Feeder breakers are grouped together on the load side of the transformer low-voltage breaker. For operating convenience, manually operated breakers should be located at the center levels, with electrically operated breakers located at the top and bottom elevations. Alternate power source breakers should be located to be as electrically and physically independent as possible. If the sources are adjacent in a breaker assembly, full barriers should be installed. Alternate sources should be interlocked so that there is no possibility for circulating currents due to two sources and so that fault duty of the switchgear cannot be exceeded by paralleling two sources for continuous operation. A common practice, especially during controlled startup and shutdown, is to briefly parallel live sources manually. This is referred to as a closed transition, live transfer, hot bus transfer, or parallel transfer. The condition is alarmed but may not be interlocked. A make-before-break interlock is sometimes provided. A modified low-voltage selective system is available, using a third transformer and two breakers in place of the bus tie breaker, and can supply either bus.

Buses may be three or four wire with the fourth wire routed to the designated compartments as required.

The optimum range of motor sizes served from low-voltage switchgear is determined by voltage regulation, circuit breaker limitations, system coordination (fault isolation), load-integrity requirements, frequency of switching operation, and economics. A typical range of motor sizes served from low-voltage switchgear at 480 V ac is 100 to 250 hp when the alternative service is 4160 V, and up to 450 hp when the alternative service is 6900 V. For further considerations, see Sections 5. and 11.

10.4.3 Continuous Ratings

Buses are sized by the manufacturer according to the main breaker continuous rating. The neutral bus in a four-wire bus system is fully rated, unless otherwise specified. Ground buses are frequently rated for 600 A continuously, but they have to carry the ground-fault current for about a minute. Circuit breaker ratings are related to frame size (generic size of breaker, i.e., maximum rating) and overcurrent device ratings. There are frame sizes available other than standard ratings. ANSI preferred ratings for power circuit breakers and molded-case breakers are as listed in Tables 10.2 and 10.3. Circuit breaker minimum continuous ratings should equal or exceed the continuous overload capability of the equipment when it is operated at its minimum voltage rating. They should also allow for unbalanced voltages for a three-phase motor where operated within its limits (negative-sequence currents). Common practice for selecting ratings is as follows:

- 1) *Transformer low-voltage circuit breaker.* 125% of transformer self-cooled winding rating, or higher than the transformer forced-cooled rating, whichever is greater.
- 2) *Single motor feeders.* The greater of 125% of motor full load current or the service factor times the full-load current. Consideration should be given to high inertia, slow starting fan motors. These loads may draw high currents for a longer than normal period.
NOTE — Cooling tower fan motors, in cold weather, can cause full load current to increase to as much as 130% of normal.
- 3) *Multiple-load feeders.* 125% of full load current of the largest motor load plus 100% of the total remaining load.
- 4) *Lighting feeders.* 125% of the estimated maximum load.

Table 10.2 — Typical Low-Voltage AC Power Circuit Breaker Ratings

Frame Size (A)	Overcurrent Device Rating (in A) at Rated Voltage		
	600 V AC	480 V AC	240 V AC
225	40–225	40–225	40–225
600	40–600	100–600	150–600
800	100–800	100–800	150–800
1600	200–1600	400–1600	600–1600
2000	200–2000	400–2000	600–2000
3000	2000–3000	2000–3000	2000–3000
4000	4000	4000	4000

Table 10.3 — Typical Molded Case AC Circuit Breaker Ratings

Frame Size (A)	Continuous Current Range Available (A)
100	15–100
225	70–225
400	70–400*
800	250–800*
1200	600–1200
1600	600–1600*
2000	1800–2000

*Full range not available in all frame styles.

10.4.4 Breaker Coordination System

10.4.4.1 General

The number of loads interrupted by the automatic operation of circuit breakers to isolate a fault depends on the selective coordination of bus supply breakers and the load feeder circuit breaker tripping and fault isolation characteristics.

Three methods of tripping coordination are in general use. Each represents a different degree of service continuity. These are identified as fully rated, selective, and cascade. It must be noted that all feeder breakers have overload trips to trip separately on any overload.

10.4.4.2 Full Rated

A fully rated substation is one in which the bus supply, bus tie, and feeder breakers have adequate interrupting capability for the fault current available to the circuit breakers. All breakers are equipped with long-time delay and instantaneous overcurrent trips. Only the load feeder breaker will open if feeder faults are less than the instantaneous trip setting of the bus supply or bus tie breaker (i.e., when there is significant load feeder impedance at the fault).

The bus supply or tie breaker will trip, however, when the fault current exceeds its instantaneous trip setting (i.e., for load feeder faults near the bus), and service continuity to all the load feeders supplied by it will be lost. This method is not recommended for power plant loads when such interruptions may cause a reduction in plant output or the possibility of damage to plant equipment.

10.4.4.3 Selective

In a selective method, the bus supply, tie, and feeder breakers all have adequate interrupting capacity for the fault current available to the breakers. Bus supply and tie breakers are equipped with overcurrent trip devices having long-time delay and short-time delay tripping characteristics. Load feeder breakers are equipped with overcurrent trip devices having long-time delay and instantaneous elements, unless they are required to be selective with other protective devices nearer the load. In this case, the feeders are equipped with trip devices having both long-time and short-time delay. In some applications, differential current protection is provided for fast clearing of faults in the transformer and power supply bus.

In the selective method, only the breaker nearest the fault trips. Service continuity is maintained through all other breakers. The bus supply breaker or tie breaker trips only for a bus fault or for feeder backup (failure of a feeder breaker). The selective method provides maximum service continuity. This method is recommended for power plant loads where loss of service results in reduced plant output or damage to equipment required for power generation.

10.4.4.4 Cascaded

In the cascaded method, only the bus supply and tie breakers have adequate interrupting capacity when load feeder impedance is small. Load feeder breakers with low (inadequate) interrupting capability are used, and the supply or tie breaker trips instantaneously to protect them when the fault current exceeds the load feeder breaker interrupting capacity. All feeder breakers are equipped with long-time delay but no instantaneous trips. The bus supply (backup) breaker is set to trip instantaneously when the fault current through the load feeder breaker exceeds 80% of the feeder breaker's interrupting capability. The cascaded system may be used where the supply or tie breaker may be tripped and supply to all load feeders may be interrupted without loss of generation or damage. This system is not recommended for power plant loads.

For fault isolation considerations and short-circuit calculations, see Sections 6. and 7.

10.4.5 AC Circuit Breaker Fault-Interrupting Ratings

10.4.5.1 Independent Manual or Power Operation

The interrupting rating of a low-voltage power circuit breaker is dependent on its design for fault current duration before interruption. Fault current duration is the result of the coordination method selected. Ratings in Table 10.4 are for breakers classified as independent manual or power operated. Other ratings may be available for higher fault duty applications.

Current-limiting fuses may be incorporated into the circuit breaker or mounted externally to permit available fault current to be as great as 200 000 A symmetrical. In this case, the circuit breaker performs its normal function of time delay and instantaneous tripping throughout its entire range of interrupting capacity. The current-limiting fuse operates to interrupt available fault current before it reaches a value that would exceed the maximum breaker rating. If fuses are used, the breaker used should be the time-delay only type, unless redundancy is desired.

10.4.5.2 Dependent Manual

Breakers with dependent manually-operated mechanisms are limited in application because the speed and force of closing are solely dependent upon the action of a human operator. Dependent manual breakers should not be used in power plants.

Table 10.4 — Typical Manual AC Power Circuit Breaker Ratings

AC Volts	Frame Size	Symmetrical Interrupting Rating With		Symmetrical Close and Latch and 30 c Time Rating	Symmetrical Fault Current Two-step Cascade
		Instantaneous Trip	Delayed Trip		
208 and 240	225	25 000	14 000	14 000	25 000
	600	42 000	22 000	22 000	42 000
	800	42 000	22 000	—	—
	1600	65 000	42 000	50 000	65 000
	2000	65 000	50 000	55 000	85 000
	3000	85 000	65 000	65 000	85 000
	4000	130 000	85 000	85 000	130 000
480	225	22 000	14 000	14 000	22 000
	600	30 000	22 000	22 000	30 000
	800	30 000	22 000	—	—
	1600	50 000	42 000	50 000	50 000
	2000	50 000	50 000	55 000	65 000
	3000	65 000	65 000	65 000	65 000
	4000	85 000	85 000	85 000	85 000
600	225	14 000	14 000	14 000	14 000
	600	22 000	22 000	22 000	22 000
	800	22 000	22 000	—	—
	1600	42 000	42 000	42 000	42 000
	2000	42 000	42 000	55 000	55 000
	3000	65 000	65 000	65 000	65 000
	4000	85 000	85 000	85 000	85 000

This section is provided for information only. Application, as identified in IEEE C37.13-1990 [B12], is as follows:

- 1) For dead-front, individually enclosed breakers with instantaneous, trip device, where the system fault availability does not exceed the following system capabilities (in rms symmetrical amperes) (see IEEE C37.13-1980 B12):

AC Voltage Rating	System Capability RMS Symmetrical Amperes
240	65 000
480	50 000
600	42 000

- 2) For dead-front, individually enclosed breakers with instantaneous trip device where the maximum instantaneous setting does not exceed 15 000 rms symmetrical amperes

- 3) For all circuit breakers equipped with selective overcurrent trip devices where the interrupting requirements do not exceed 15 000 rms symmetrical amperes
- 4) For all circuit breakers without direct acting overcurrent trip devices where the interrupting requirements do not exceed 15 000 rms symmetrical amperes

10.4.5.3 Molded-Case

Molded-case circuit breaker types, frame sizes, and trip coil ratings appear in Table 10.5. Current-limiting fuses can be incorporated into the molded-case circuit breaker, which permits available fault current to be as high as 200 000 A symmetrical.

10.4.6 DC Circuit Breaker Fault Interrupting Ratings

DC power circuit breakers normally used for power plant application are classified as general purpose. Systems that have short-circuit capacities greater than 100 000 A should use a semi high-speed or high-speed breaker that limits fault current, i.e., interrupts fault current before it reaches the maximum value.

The general purpose breaker is used extensively at voltages up to 250 V dc with short-circuit currents of 100 000 A. It has an interrupting time of .030 to .040 s and, generally, will not limit the fault current. General purpose breakers without instantaneous trip should not be applied when the available system fault current exceeds the short-time rating of the circuit breaker.

The dc breakers are either electrically or manually operated. Manually operated breaker applications must meet the following criteria (See IEEE C37.14-1979 [B13]):

- 1) The breaker is dead front or enclosed.
- 2) The breaker is equipped with an instantaneous trip set at 15 000 A or less.

The available short-circuit current does not exceed 50 000 A. Available ratings for dc rated power and molded-case circuit breakers are in Tables 10.6 and 10.7.

10.4.7 Electrical Protection, Control, and Interlocks

The following devices, accessories, features, and nominal control voltages are available on power circuit breakers.

10.4.7.1 Protection Devices

Overcurrent devices:

- 1) Electromechanical or solid-state direct acting trip devices
- 2) Ground sensors
- 3) Protective relays
- 4) Fuses

Undervoltage devices:

- 1) Electromechanical direct acting trip devices
- 2) Protective relays

Table 10.5 – Typical AC Molded Case Circuit Breaker Ratings

Maximum Amperes AC Maximum Voltage	Circuit Breaker Frame	Current Continuous (A)	AC (V)	Maximum Interrupting Rating Symmetric RMS Amperes
100 A 480 V	100 A	15–100	240	14 000
			480	14 000
100 A 600 V	100 A	15–100	240	18 000
			480	14 000
			600	14 000
		15–100	240	65 000
			480	25 000
			600	18 000
225 A 600 V	225 A	70–225	240	22 000
			480	18 000
			600	14 000
		250–400	240	42 000
			480	30 000
			600	22 000
400 A 600 V	400 A	70–400	240	42 000
			480	30 000
			600	22 000
		125–400	240	65 000
			480	35 000
			600	25 000
		150–400	240	200 000*
			480	100 000*
			600	100 000*
800 A 600 V	800 A	250–800	240	42 000
			480	30 000
			600	22 000
800 A 600 V	800 A	400–800	240	65 000
			480	35 000
			600	25 000

Maximum Amperes AC Maximum Voltage	Circuit Breaker Frame	Current Continuous (A)	AC (V)	Maximum Interrupting Rating Symmetric RMS Amperes
		400–800	240	200 000*
			480	100 000*
			600	100 000*
1600 A	1600 A	600–1600	240	65 000
600 V			480	50 000
			600	42 000
		800–1600	240	200 000*
			480	100 000*
			600	100 000*
2000 A	2000 A	1800–2000	240	65 000
			480	50 000
			600	42 000
		1800–2000	240	200 000*
			480	100 000*
			600	100 000*

*Fused

Table 10.6 — Typical Power Circuit Breaker Rating, 250 V DC

Frame Size	Overcurrent Device Rating (A)	Maximum Interrupting Current at 250 V DC (A)
225	15–225	15 000
600	40–600	25 000
1600	200–1600	50 000
3000	2000–3000	75 000
4000	4000	100 000
5000	5000	100 000
6000	6000	100 000

Table 10.7 — Typical Molded Case Circuit Breaker Ratings, 125-250 V DC

Frame Size	Overcurrent Device Range (A)	Voltage (DC)	Interrupting Current (A)
50	15–50	125	5000
100	15–100	125	5000
100	15–100	250	10 000
225	70–225	250	10 000
400	125–400	250	20 000
600	125–600	250	20 000
800	125–800	250	20 000

10.4.7.2 Control Devices

- 1) Closing motor or solenoid
- 2) Shunt trip
- 3) Auxiliary switches
- 4) Antipump relay
- 5) Auxiliary relays

10.4.7.3 Interlocks Available

- 1) Breaker racking — drawout type only (cell switch)
- 2) Breaker interchangeability — drawout type only
- 3) Mechanical lockout on automatic trip
- 4) Alarm switch
- 5) Hinged door interlock — drawout type only
- 6) Mechanical transfer
- 7) Key interlock

10.4.7.4 Nominal Control Voltages

- 1) 120 V ac, 60 Hz
- 2) 240 V ac, 60 Hz
- 3) 48 V dc
- 4) 125 V dc
- 5) 250 V dc

Typical control circuits for stationary and drawout breakers are readily available in manufacturer's literature.

10.5 Combination Starter Panels (Motor Control Centers [MCC])**10.5.1 Description of Equipment****10.5.1.1 General**

This section applies to combination starter panels (MCC) that supply electric power to low-voltage auxiliaries such as motors, motor-operated valves, transformers, distribution panelboards, resistance heaters, etc.

A combination starter panel (MCC) is a floor-mounted assembly of one or more enclosed vertical sections containing primarily combination starters. The assembly has a common horizontal power (main) bus supplying the vertical sections. A combination starter unit may be a contactor combined with either a molded-case circuit breaker or a fusible disconnect switch. Manually operated units may be circuit breakers or fusible switches. Combination starters or feeder breaker units in separate compartments are mounted one above the other in the vertical sections. The sections usually incorporate vertical buses connected to the main bus, thus extending the common power supply to the individual units. Units may also be connected directly to the main bus by suitable wiring.

Individual control units are usually housed in separate metal-enclosed compartments, each with its own door. The remotely controlled units include circuit breakers or fusible combination starters. Feeders may be manually controlled at the starter panel, and thus require only circuit breakers or fused switches. Normally, units that are 36 in or less in height are of plug-in design, and larger units are bolted in. All units are front-removable. Other apparatus such as lighting panelboards, dry-type transformers, instrumentation, etc., may also be mounted in the combination starter panel.

Starter panel (MCC) vertical sections are nominally 20 in wide and 90 in high, 72 in of which is available for the control units. For front-of-board mounting of units, the vertical sections are either 15 in or 20 in deep. For back-to-back mounting of units, the vertical sections are 20 in deep. For front-of-board mounted units, the rear of each vertical section has two half-height, removable covers on the 15 in deep sections, and two half-height, hinged doors on the 20 in deep sections. These are typical dimensions and may change as products develop with designs offered by different manufacturers.

Horizontal top and bottom wireways across the full width of the structure provide conduit entry and wiring runs. The top wireway is in front of, and isolated from, the horizontal main bus. The bottom wireway is positioned below the termination of the vertical bus. Compartment doors can be full width across the section. Access to the vertical wireway is then possible only by opening the unit doors. With a separate, full height, vertical wireway door, the compartment doors are narrower, and the vertical wireway door can be opened at any time with all units energized. The wireway door is usually removable.

Main and vertical buses can be of copper, silver-plated copper, tin-plated copper, or tin-plated aluminum. Tin plating of the copper or aluminum bus increases corrosion resistance and provides a lubricating effect that facilitates stabbing of the drawout units on the vertical bus. Tin plating is less desirable for short-circuit conditions because the melting point of tin is lower than that of silver. Vertical bus contact surfaces are subjected to wear by repeated removal and insertion of the drawout starter units. The amount of abrasion experienced is directly related to the contact force with which the stab engages the bus, the number of stabbing operations, and the lubrication of the parts in contact with each other. The horizontal bus is isolated at the front by barriers that provide positive protection against accidental faults and can be removed or slid sideways to permit access for inspection or repair. The vertical bus is isolated at the front with an insulating barrier that has stab holes through which the units stab onto the bus. Connections between the horizontal and vertical buses are bolted using conical dished steel washers to maintain contact pressure during differential thermal expansion of the bus and the bolts. A tin-plated aluminum or copper ground bus, extending the full length of the assembly, is mounted at the top or bottom of the structure in the horizontal wireway. An insulated neutral bus is available in addition to the ground bus.

10.5.1.2 Ratings

Starter panel (MCC) rating is based on voltage, continuous and short-circuit current, and frequency (if other than 50 or 60 Hz). The ratings include the number of phases and line-to-line voltage ratings of 120, 208, 240, 480, or 600 V ac. In accordance with UL 508-1988 B30, combination starters are rated to interrupt fault currents, with magnetic-only circuit breakers, of 14 000 A, 22 000 A, 25 000 A, etc., based on tests using the impedance of the breaker, starter, and overload relays plus 4 ft of wire. Horizontal bus capacities from 600 A minimum to 3000 A maximum and vertical bus capacities of 300, 600, 800, and 1200 A are available. Bus bracing levels of 22 000, 42 000, 65 000, and 100 000 rms A symmetrical are available.

10.5.1.3 Load Grouping

Although combination motor-starter panels are primarily intended to house and electrically feed multiple combination motor starter units, it is often convenient to include manually switched feeder units, single-phase and three-phase dry-type distribution transformers, lighting panelboards, current-limiting reactors, and metering equipment. If the length of the control center is a critical factor, the back-to-back arrangement can be considered, provided that both sides are accessible.

The larger combination starters should be mounted at the bottom of the vertical section for vertical stability and ease of handling.

10.5.1.4 Motor Sizes

The maximum motor sizes to be supplied from NEMA size full-voltage, single speed, nonreversing or reversing circuit breakers or fusible disconnect combination starters are as follows:

NEMA Size	Starter Ratings	
	Maximum Horsepower	
	230 V	460-575 V
1	7.5	10
2	15	25
3	30	50
4	50	100
5	100	200
6	200	400

NOTE — Although smaller size starters are manufactured, NEMA Size 1 is recommended as a minimum size to be used in power plant applications. Some designers do not use starters larger than Size 3. Space limitations due to wire size and the resulting problems with poor connections and possible conductor failure preclude the use of Size 4 or larger. Some owners prefer not to use starters larger than Size 4 because the lack of a drawout feature does not facilitate maintenance.

10.5.1.4.1 Jogging Duty

Jogging is the momentary operation of the motor, from rest, to accomplish small movements in the driven equipment. Special control circuits are required that open the contactor holding circuit when closing the start control circuit and may also bypass the overload circuit during the jog mode. Bypassing the overload circuit is not recommended. A starter one size larger than normal should be used when jogging is to be performed frequently or for long periods to reduce contact overheating and burning due to frequent interruption of motor inrush currents.

10.5.1.5 Maximum Fuse Sizes

The maximum rating or setting of motor branch circuit protective devices (fuses and breakers) is as listed in Table 430-152 ANSI/NFPA 70-1990 (NEC) [2]. (Part D, Sections 430-51 through 58 of the NEC [1981] describes motor branch circuit short-circuit and ground fault protection. While the NEC does not apply to power plants, it is used here as a convenient reference.)

The rating of a fusible-switch/combination starter is based on overfusing of time-delay or current-limiting time-delay (dual element) fuses and one-step overfusing for standard one-time fuses. A unit using fuses whose continuous current rating is larger than given in Table 10.8 does not have an established short-circuit rating.

Table 10.8 — Maximum Allowable Fuse Size Used With Starter Continuous Current Ratings

NEMA Size Starter	Time-Delay or Current-Limiting Time-Delay Fuse Amperes	One-Time Fuse Amperes
1	30	60
2	60	100
3	100	200
4	200	400
5	400	600
6	—	1200
7	—	1800

Overfusing is accomplished by oversizing the fuses to prevent opening of the fuses on inrush currents, but still allowing the fuses to provide protection under overload or fault conditions.

10.5.2 Protection and Control

10.5.2.1 General

Short-circuit protection for combination starters is provided by a fuse or breaker, as described in 10.5.1.5. An overload relay gives motor running overcurrent protection. Control of and indication of the position of the starter is accomplished by the use of pushbuttons, selector switches, indicating lights, control relays, auxiliary contacts, and a control transformer.

10.5.2.2 Overload Heater Sizing

Heaters for motor starter overload relays are selected as required by the motor ampere rating, service factor, motor temperature rise, and ambient temperature. The heater tables published by the manufacturers are applicable for both two and three phase overload protection. Three-phase overloads are frequently used in power plants. Article 430-37, Part C of the NEC [2] requires three overload devices (one in each phase).

The heater tables show a minimum and maximum ampere rating for each heater. Some heaters have two ampere ranges for a low and high position of the coil on the overload relay. The motor full load amperes should be between the minimum and maximum ampere values of the heater selected. The approximate ultimate tripping current in a 40 °C ambient can be determined by multiplying the minimum current by 1.25. The heater selection tables are for use with a 40 °C rise motor having a 1.15 service factor and the overload heater in an ambient of 40 °C. Whenever the ambient temperature surrounding the overload relay varies with respect to that surrounding the motor, an ambient compensated thermal-overload relay should be used. For example, outdoor control centers for pumping loads that are exposed to high ambient temperatures during the day and low ambient after sundown may require compensated overload relays to protect submersible pump motors operating in a relatively constant ambient.

When the motor operates in a significantly higher or lower ambient temperature than the starter panel. Table 10.9 provides guidance for selection of noncompensated overload heaters. Manufacturer's literature explains how to select heaters and should be consulted for each particular installation.

10.5.2.2.1 Effects of Heaters on Short Circuits

Heater impedance can be a controlling factor of short-circuit let-through current for small motors with full-load current up to 12 A. Above this value, heater resistance does not have an appreciable effect. The effect of heater impedance on short-circuit current is also proportional to system voltage.

10.5.2.3 Starter Control Transformer and Control Circuits

When specified, control power transformers are furnished to provide 115 or 120 V control circuits. When a single 250 V secondary control circuit fuse is supplied, overcurrent protection should be provided using the latest edition of the NEC [2] as a guide. The other conductor of the secondary circuit is grounded. If the other conductor of the secondary circuit is not grounded, two fuses should be supplied. Typical sizes of control transformers normally supplied are listed in Table 10.10. These ratings are adequate to handle the starter coil current and three pilot lights. If additional burdens and long external control circuits are expected, larger transformers should be specified. The use of a 500 VA control transformer for all sizes would allow future flexibility. Manufacturers may not be able to supply large control transformers due to the physical limitations of the compartment size.

Table 10.9 – Heater Requirements by Operating Conditions

Motor continuous rating °C rise	Ambient same at starter and rotor	Ambient higher at starter than motor	Ambient lower at starter than at motor
1.15 service factor 40 °C rise	As specified from tables	One size larger than specified for each 15 °C difference	One size smaller than specified for each 15 °C difference
1.0 service factor 40 °C rise	One size smaller than for 1.15 service factor above	One size smaller than for 1.15 service factor above	One size smaller than for 1.15 service factor above 40 °C rise

Table 10.10 – Control Transformers Typically Provided per Starter Size

Starter Sizes and types	Control Power Transformer Volt-Amperes
Size 1	60 (100 recommended)
Size 2	100
Size 3, except RVNR and 2S-1W	200
Size 4, except RVNR	250
Size 3 and 4 RVNR	250
Size 5 and 6	250
Size 3 2S-1W	250

RVNR = reduced voltage nonreversing

2s-1W = full voltage, nonreversing, two speed, one winding

10.5.2.3.1 Starter Pickup and Dropout Characteristics

Typical values for contactors based on coil voltage rating are

- 1) Pickup volts 85% (or less) of rated coil voltage when not using a control power transformer; 90% (or less) of rated coil voltage when using a control power transformer
- 2) Dropout volts 65% (or less) as voltage decreases

10.5.3 Interlocks

Auxiliary contacts for electrical interlocks required for the starter control function are supplied as standard. Additional auxiliary contacts, either normally open or normally closed, are available for electrical interlocking and holding circuits in quantities dependent on the starter size. Additional uses for auxiliary contacts are remote indication and alarm functions. Different manufacturers have different quantities of auxiliary contacts available. Control relays are also available with normally open and normally closed contacts.

Interposing relays may be required, if the wiring of the control circuits are long, to reduce the control circuit voltage drop. If the operating coil of the starter is rated for a different voltage than the control circuit, an additional control relay is required (for example, 480 V operating coil on the Size 3 and above starters).

The manual disconnect or circuit breaker operating mechanism has a mechanical interlock built into it for two personnel safeguard purposes:

- 1) To prevent the unit door from being opened with the disconnect in the ON position
- 2) To prevent the disconnect from being closed when the door is open

Both of these functions can be defeated usually for test and maintenance purposes with a recessed, screwdriver operated defeater.

10.5.4 Wiring

The extent to which a manufacturer, as directed by the order, will provide wiring of combination starter panels (MCC) is classified in NEMA ICS 2-1988 [5] and is described below.

10.5.4.1 Definition of NEMA Class and Type

- 1) *Class I.* A mechanical grouping of control, feeder, or other units arranged in a common assembly with power connections from the main bus to the units. Interwiring and electrical interlocking between units and/or remote devices are not included.
- 2) *Class II.* Same as Class I, except that interwiring and interlocking between units and interlocking provisions for remote devices are included.
- 3) *Type A.* Terminal boards for load or control connections are not included (applies to Class I only).
- 4) *Type B.* Control and load terminal boards are provided for Size 3 starters or smaller (applies to both Class I and II).
- 5) *Type C.* Grouping of Type B units with control wiring and load wiring for Size 3 starters and smaller extended to master terminal boards at the top or bottom of each vertical section (applies to both Class I and II).

10.6 Panelboards

10.6.1 General

A panelboard normally contains manually operated load-circuit switches that usually have automatic fault current isolating devices and include incoming power supply circuit switching with fault interrupting devices and supply circuit interconnections. Panelboards are used for the distribution of electrical energy up to voltages that seldom exceed 600 V. Panelboards are used for manual switching and automatic fault isolation for groups or single branch circuits serving lighting, heating, and power loads. Circuit breakers or manually operated switches with fuses are used to provide overcurrent protection and switching. They are classified as lighting or distribution panelboards. Classification and limitations are established by the Underwriters Laboratories, Inc.¹⁶ and the NEC [2].

¹⁶Underwriters Laboratories, Inc., 333 Pfingsten Road, Northbrook, IL 60062-2096, USA.

10.6.1.1 Lighting Panelboards

A lighting panelboard is a panelboard having more than 10% of its overcurrent devices rated 30 A or less, for which solidly grounded neutral connections are provided. If a lighting panelboard is fed from a circuit that is protected for more than 200 A, it must be protected on its supply side not in excess of its rating. If a lighting panelboard is fed from a circuit that is protected for 200 A or less, additional supply side protection is not required, provided that the circuit overcurrent protection does not exceed the rating of the panelboard. The board is limited to a maximum of 42 single-pole feeder circuits with overcurrent devices per panel, excluding the main breaker(s) (see Section 384-15 of the NEC [2]).

10.6.1.2 Power Distribution Panelboards

Distribution panelboards are all other types of panelboards. There is no limitation as to the size of mains or number of branch circuits, except as dictated by manufacturer's standards. Panelboards are available with combination current-limiting fused circuit breakers for the feeder circuits.

10.6.1.3 Multisection Panelboards

If a larger panelboard is required than allowed by the number of circuit protective devices and physical size limitations, additional sections, mounted in their own boxes, can be bussed together and either subfed or throughfed from the main panel. Subfed panels are fed from a feeder breaker on the main panel, while throughfed panels are directly tapped off the main panel bus. Consult the manufacturers and standards for detailed practices of installation and protection.

10.6.2 Panelboard Ratings

10.6.2.1 Short-Circuit Current Ratings

The short-circuit rating of a panelboard is limited to the interrupting rating of the lowest rated device. When the panelboard is applied within this rating, bus bar bracing is adequate to withstand the forces exerted by transient fault current. Standard ratings for circuit breakers and fuses used in panelboards appear in Tables 10.11 and 10.12. These ratings can be increased, up to 200 000 A, by the use of current-limiting fuses in the supply (main) circuit.

Table 10.11 — Circuit Breaker Panelboards Typical Interrupting Capacity — RMS Amperes

Breaker Frame	Ampere Ratings	120 V AC		240 V AC		480 V AC		600 V AC		125/250 V DC	250 V DC
		Asym-metric	Sym-metric	Asym-metric	Sym-metric	Asym-metric	Sym-metric	Asym-metric	Asym-metric		
100	15–70	5000	5000	5000	5000	—	—	—	—	—	—
	70–100	5000	5000	5000	5000	—	—	—	—	—	—
100	15–100	7500	7500	7500	7500	—	—	—	—	500	—
100	15–100			10 000	10 000	—	—	—	—	—	—
	15–100			15 000	14 000	15 000	14 000	—	—	—	—
	15–100			20 000	18 000	15 000	14 000	15 000	14 000	—	10 000
225	70–225			25 000	22 000	20 000	18 000	15 000	14 000	—	10 000
400	125–400			50 000	42 000	35 000	30 000	25 000	22 000	—	20 000
800	125–800			50 000	42 000	35 000	30 000	25 000	22 000	—	20 000

Table 10.12 — Typical Fused Panelboard

Voltage	Switch Rating (Sym A) Branch or Main	Panelboard Short-Circuit Rating, A			
		Using Class H Fuses	Using Class J Fuses	Using Class R Fuses	Using Class L Fuses
2, 3 poles	30, 60, 100, 200	10 000	200 000	200 000	—
240V	400, 600	10 000	200 000	—	—
ac	800, 1200	10 000	—	—	200 000
2, 3 poles	30, 60, 100, 200	10 000	200 000	200 000	—
600 V ac	400, 600	10 000	200 000	—	—
250 V dc	800, 1200	—	—	—	200 000

10.6.2.2 Continuous Current Ratings

Panelboards have continuous current ratings and are furnished with lugs up to 1200 A (special ones will go up to 1600 A). Panelboards have main breakers or switches up through 1200 A. Branch circuit breakers or fusible switches have ratings of 15 through 1200 A.

10.6.2.3 Voltage Ratings of Standard Panelboards

AC	DC
120/208	125
120/240	
240	125/250
277/480	250
480	
600	

10.7 Fuses

10.7.1 General

Properly applied fuses provide short-circuit and overcurrent protection. They are used to protect incoming lines, motor circuits, branch feeders, and circuit breakers for short-circuit magnitudes from 5000 to 200 000 A.

10.7.2 Application

Cartridge fuses are used for power plant 0 to 600 V applications. Specific information is available in the references and manufacturers' literature. General information is as listed in Table 10.13.

Table 10.13 — Application of Cartridge Fuses

Circuit Type	Voltage	Fuse Type		
		Class	Int Cap	Time Delay
Control	250, 600	One time	(NEC) 5000 A	No
	250, 600	H	10 000 A	No
	300	G	100 000 A	Yes
Power, Lighting	250, 600	Onetime	(NEC) 5000 A	No
	250, 600	H	10 000 A	No
	250, 600	K	10 000 A	Yes
	600	J	200 000 A	Yes
Motors	250, 600	H	10 000 A	Yes
	250, 600	K	10 000 A	Yes
	600	J	200 000 A	Yes
	600	J	200 000 A	Yes
Power Circuit Breaker	600	K	10 000 A	Yes
	600	J	200 000 A	Yes
	600	L	200 000 A	Yes

10.8 Insulation Levels of Equipment

Field conducted dielectric withstand tests should be at least 75% of the values in Table 10.14.

Table 10.14 — Typical Electrical Equipment Insulation Levels

Rated Voltage	Dielectric Withstand (kV)	Impulse Crest (kV)
240	2.2	—
480	2.2	—
600	2.2	—
4160	19	60
7200	36	95
13 800	36	95
14 400	50	110

10.9 Equipment Layout and Installation

Please refer to Section 13. for further information.

10.9.1 Phasing

Normal phasing, unless otherwise specified, is for a phase rotation 1-2-3 or A-B-C, left-to-right, top-to-bottom, and front-to-back when facing the front of the compartment. Phasing checks must be made before energization for dual feeds to buses.

10.9.2 Grounding

Provide protective grounding as discussed in IEEE Std 80-1986 [3]. Switchgear and load control centers are provided with a ground bus located at the bottom and extending the length of the equipment. This bus is for protective grounding and is not a load carrying bus. Switchgear and combination starter panel ground buses should be grounded at both ends to the ground grid at two different locations. The lugs usually accommodate an American Wire Gage (AWG) No. 2 through 4/0 copper wire. The size of the copper grounding lugs and wires should be in accordance with Section 250 of the NEC [2]. Panelboards should be deadfront and grounded.

10.9.3 Safety

Modern switchgear provides for safety by use of metal-enclosed, dead-front, compartmentalized design and use of noncombustible, moisture resistant materials. The following items should also be considered:

- 1) Adequate area lighting with a standby source should be provided.
- 2) Switchgear units should be labeled in front and rear to match the single-line diagram.
- 3) Equipment should be applied within its rating.
- 4) Entrance to live parts should be barred so that inadvertent contact is prevented.
- 5) Live parts should be isolated with a grounded screen.
- 6) Live parts should be insulated in maintenance working areas, and provisions should be made for temporary barriers over live parts exposed during maintenance work.
- 7) Positive disconnect means, with visible breaks and with provisions for securing in an open position through protective tagging or locking, should be provided for switches, disconnects, and fuses.
- 8) Before the equipment is put in service, thorough visual, mechanical, electrical, and operational tests should be made.
- 9) "CAUTION" warning signs should be provided as appropriate.

10.10 Shipping and Storage

Shipping sections should be specified according to the ability to handle the size and weight at the site. Site handling must consider door openings, elevator or crane availability, obstructions of existing equipment, piping, and ducts. Upon receipt and before acceptance, equipment should be inspected for possible shipping damage and, if damage is observed, the manufacturer and carrier should be notified. Equipment should be installed in its permanent position as soon as possible. If the equipment cannot be installed and must be stored, it should be left in its protective envelope and stored in an indoor area protected from high humidity and corrosive gases. Space heaters may be provided by the manufacturer for use during storage to prevent moisture damage. The power leads from the space heaters should be brought outside the protective envelope for connection to the power source.

Breakers should be left in their shipping cartons, sealed and covered with nonabsorbent covering. Heaters or lights should be used to prevent condensation. An application of lubricant will be necessary for certain parts if the storage is for a prolonged time.

10.11 Maintenance

10.11.1 General

Good maintenance begins in the design by providing application equipment, adequate space, good environment, accessible electrical and mechanical services, and basic tools. Consulting with the maintenance engineer during the design and equipment procurement period regarding maintenance requirements is recommended. The manufacturers' literature is to be consulted for specific requirements for its equipment. When servicing or adjusting the electrical equipment, refer to the applicable drawings covering the specific panel, any related interconnection drawings, and instruction/maintenance manuals.

- 1) Equipment should be clean at all times. Any accumulation of dust and dirt should be removed with an industrial vacuum cleaner or by manual cleaning, when the bus is deenergized.
- 2) Periodic inspection should be made of all devices to ensure that the apparatus is functioning properly.
- 3) Badly worn or pitted contacts should be replaced as soon as possible.
- 4) Oil based lubrication should not be applied to any part of an electrical contact. However, special contact lubes are available to reduce wear and/or pitting.
- 5) Emery paper, sandpaper, or files should not be used to clean or dress up any portion of electrical equipment. For applications requiring a sanding operation, aluminum oxide paper, which will not leave sand or metal particles on contact surface areas, should be used.
- 6) All bolted connections, nuts, and screws should be inspected for tightness, following the manufacturer's recommended torque values.
- 7) All cables should be inspected for tight connections and ample support, following the manufacturer's recommended torque values.
- 8) Control wiring should be inspected for signs of wear and damage.
- 9) Resistors and other devices that are prone to overheating should be inspected.

If vacuum breakers and/or gas breakers have been purchased, the appropriate maintenance guides for this specialized equipment should be consulted.

10.11.2 Frequency of Inspection

Frequency of inspection depends on installation conditions and can be best determined by experience. Inspections should be performed at least once a year, or per manufacturer's recommendations.

10.11.2.1 Circuit Breakers

Circuit breakers are to be maintained at the intervals stated in the, instruction book. Local environment and breaker application must be considered in developing a maintenance program. Consideration should be given to such variables as ambient temperature, actual continuous current, number of operations, type of interrupting duty, and any unusual local conditions, e.g., corrosive atmosphere.

10.11.3 Activities

Typical maintenance activities for the equipment are as follows.

10.11.3.1 Switchgear

- 1) Operating the breaker.
- 2) Inspecting the breaker for loose or damaged parts.
- 3) Dressing or replacing contacts as required.
- 4) Cleaning insulating parts.
- 5) Making recommended adjustments.
- 6) Checking tightness of electrical connections per the manufacturer's torque recommendations.

- 7) Checking calibration and operation of the overcurrent and undervoltage trip devices.
- 8) Making dielectric tests of the power, control, current, and potential circuits.
- 9) Checking instrument and control switches and inspecting their contacts.
- 10) Examining indicating lamps and replacing all those that are burned out.
- 11) Inspecting bus bars and connections to see that they are in proper condition. If they are overheating, checking for poor or loose connections or for overload.
- 12) Checking for proper condition of instrument transformers. Replacing burned out fuses (if any). Checking primary and secondary connections.
- 13) Examining automatic shutters for proper operation.
- 14) Examining all safety interlocks.

10.11.3.2 Combination Starter Panels

The following additional items should be noted when servicing control centers:

- 1) The silver cadmium contact points of line starters should not be sanded. In the event of wear, all contacts should be replaced as a group to avoid misalignment problems.
- 2) Connections should be kept tight. Special attention should be given to the overload relay thermal element (heater) connections to ensure proper functioning.
- 3) Authorized personnel only may open the door while the starter unit is energized by defeating the mechanical interlock between the operating mechanism and the unit door.

10.11.3.3 Panelboards

A complete maintenance guide is contained in NEMA PB1.1-1986 [6].

10.11.4 Spare Parts

The manufacturer will recommend spare parts upon request based on experience and testing. Total assemblies are the best insurance for fast replacement. Only renewal parts that will be required to ensure timely maintenance for normal operation should be stocked. A nominal quantity of spare parts is 10% of the quantity installed.

10.11.5 Accessories

The following accessories may be provided with the equipment (see manufacturer's catalog):

- 1) Breaker handling equipment
- 2) Extension control cable
- 3) Specialized adjusting tools

10.12 Bibliography

[B1] ANSI C2-1990, National Electrical Safety Code.

[B2] ANSI C37.05-1964 (Withdrawn), American National Standard for Methods for Determining the Values of a Sinusoidal Current Wave and a Normal-Frequency Recovery Voltage for AC High-Voltage Circuit Breakers.

[B3] ANSI C37.07-1969 (Withdrawn), American National Standard for Interrupting Capability Factors for Reclosing Service for AC High-Voltage Circuit Breakers.

[B4] ANSI C37.9-1991, American National Standard Test Code for AC High-Voltage Circuit Breakers Rated on a Total Current Basis.

[B5] ANSI C37.11-1979 (Withdrawn), American National Standard Requirements for Electrical Control for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis and a Total Current Basis.

[B6] ANSI C37.16-1988, American National Standard for Preferred Ratings, Related Requirements and Application Recommendations for Low-Voltage Power Circuit Breakers and AC Power Circuit Protectors.

[B7] ANSI C37.17-1979 (Reaf 1988), American National Standard for Trip Devices for AC and General Purpose DC Low-Voltage Power Circuit Breakers.

[B8] ANSI Z55.1-1967 (Withdrawn), American National Standard for Gray Finishes for Industrial Apparatus and Equipment.

[B9] IEEE C37.04-1979 (Reaf 1988), IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (ANSI).

[B10] IEEE C37.09-1979 (Reaf 1988), IEEE Standard Test Procedure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (ANSI).

[B11] IEEE C37.010-1979 (Reaf 1988), IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (ANSI).

[B12] IEEE C37.13-1990, IEEE Standard Low-Voltage AC Power Circuit Breakers Used in Enclosures (ANSI).

[B13] IEEE C37.14-1979 (Reaf 1985), IEEE Standard Low-Voltage DC Power Circuit Breakers Used in Enclosures (ANSI).

[B14] IEEE C37.20.1-1987, IEEE Standard for Metal-Enclosed Low-Voltage Power Circuit Breaker Switchgear (ANSI).

[B15] IEEE C37.20.2-1987, IEEE Standard for Metal-Clad and Station-Type Cubicle Switchgear (ANSI).

[B16] IEEE C37.20.3-1987, IEEE Standard for Metal-Enclosed Interrupter Switchgear (ANSI).

[B17] IEEE C37.23-1987, IEEE Standard for Metal-Enclosed Bus and Calculating Losses in Isolated-Phase Bus (ANSI).

[B18] IEEE C37.27-1987, IEEE Application Guide for Low-Voltage AC Nonintegrally Fused Power Circuit Breakers (Using Separately Mounted Current-Limiting Fuses) (ANSI).

[B19] IEEE C37.90-1989, IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus (ANSI).

[B20] IEEE C57.13-1978 (Reaf 1986), IEEE Standard Requirements for Instrument Transformers (ANSI).

[B21] IEEE Std 141-1986, IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems (ANSI).

[B22] NEMA EI 2-1966 (Rescinded), Instrument Transformers.

[B23] NEMA PB1-1984, Panelboards.

[B24] NEMA SG 3-1990, Low-Voltage Power Circuit Breakers.

[B25] NEMA SG 4-1990, Alternating Current High-Voltage Circuit Breakers.

[B26] NEMA SG 5-1990, Power Switchgear Assemblies.

[B27] NEMA WC 3-1980 (Reaf 1986), Rubber-Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy (ICEA S-19-81).

[B28] UL 67-1988, The Standard for Panelboards.

[B29] UL 198-1988, The Standard for Fuses. UL 845-1987, The Standard for Motor Control Centers.

[B30] UL 508-1988, The Standard for Industrial Control Equipment.

11. Electric Motor Characteristics and Applications

11.1 Introduction

Electric motors are used to drive all or almost all of the rotating auxiliary drives in a steam-electric generating station. These motors range in size from a fraction of a horsepower to many thousands of horsepower. This section will concentrate on the effects of these motors on electric power service system design and the effects of the electric power system on the application and operation of the motors. The vast majority of auxiliaries drive motors are squirrel cage induction; some are salient pole synchronous; a few are wound rotor induction; and there are a few dc motors that operate from the station battery system. For fossil fuel plants, the larger motors are applied to such auxiliary drives as

- 1) Coal crushers and pulverizers
- 2) Condensate or hotwell pumps
- 3) Condensate booster or feedwater booster pumps
- 4) Boiler feed pumps
- 5) Boiler recirculating pumps
- 6) Primary-air fans
- 7) Forced draft fans
- 8) Gas recirculating fans
- 9) Induced draft fans
- 10) Condenser circulating water pumps
- 11) Cooling tower pumps and fans
- 12) Service water pumps
- 13) Soot blower air compressors
- 14) Coal conveyors
- 15) Air compressors
- 16) Ash pumps
- 17) Drive motor for rotating dc exciter for main generator (older stations)

11.2 References

- [1] ANSI C50.41-1982, American National Standard Polyphase Induction Motors for Power Generating Stations.¹⁷
- [2] ANSI/AFBMA 9-1990, Load Ratings and Fatigue Life for Ball Bearings.¹⁸
- [3] ANSI/NFPA 70B-1990, Electrical Equipment Maintenance.¹⁹
- [4] IEEE C37.010-1979 (Reaff 1988), IEEE Standard Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (ANSI).²⁰
- [5] IEEE C37.96-1988, IEEE Guide for AC Motor Protection (ANSI).
- [6] IEEE Std 112-1991, IEEE Standard Test Procedure for Polyphase Induction Motors and Generators.
- [7] NEMA MG1-1987, Motors and Generators.²¹

¹⁷ANSI publications are available from the Sales Department, American National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036, USA.

¹⁸AFBMA publications are available from the Sales Department, American National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036, USA.

¹⁹NFPA publications are available from Publications Sales, National Fire Protection Association, 1 Batterymarch Park, P.O. Box 9101, Quincy, MA 02269-9101, USA.

²⁰IEEE publications are available from the Institute of Electrical and Electronics Engineers, Service Center, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA.

²¹NEMA publications are available from the National Electrical Manufacturers Association, 2101 L Street NW, Washington, DC 20037, USA.

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11.3 Large Polyphase AC Motors

11.3.1 Induction Motors

The polyphase induction motor has been the work horse of industry from the beginning of the use of ac power. It has achieved and maintained this position by virtue of its simplicity and ruggedness. The standard line of induction motors includes squirrel cage motors and wound rotor motors plus derivatives of these basic motors, such as multispeed motors. This discussion of large induction motors will concentrate on motors of approximately 200 hp and above.

11.3.1.1 Principles of Construction and Operation

The winding of an induction motor, to which the power supply is connected, is distributed around the stator and produces, in the air gap, a magnetic field revolving in synchronism with the power supply frequency. As the magnetic field revolves, the flux linking the conductors of the winding in the rotor changes, generating a voltage and, thus, a current in that winding that, in turn, produces a flux opposing the generating or stator flux. The interaction of the stator and rotor fluxes produces a torque and causes the rotor to follow the rotating stator flux.

If the rotor were to rotate at the exact speed of the rotating magnetic field, the flux would no longer cut conductors, and, therefore, torque would not be developed. The difference between the rotational speed of the stator flux and the rotor mechanical speed is known as slip.

The electrical analysis for this phenomena is quite similar to that for a transformer. Thus, it has become the practice to refer to the stator of the motor as the primary and the rotor as the secondary.

If the secondary conductors are arranged like bars of a squirrel cage, and if the squirrel cage is arranged to allow rotation, the force of the interaction of the stator and rotor fluxes on the conductors will rotate the squirrel cage. In practice, the uninsulated bars of the squirrel cage are embedded axially in a laminated iron rotor close to the periphery of the rotor and are connected together through a suitable short-circuiting ring at each end of the rotor. This simple construction makes the squirrel cage motor the most rugged and the least expensive of all types of induction motors. Variations in rotor bar design provide variations in the performance characteristics of the induction motor, especially torque vs. speed and current vs. speed characteristics.

The following principles of induction motor operation are presented because of their value in dealing with problems in application of induction motors:

- 1) All torques of an induction motor, at a given slip, vary approximately as the square of the voltage applied to its terminals.
- 2) Low rotor resistance results in high full load speed (low slip), high efficiency (low rotor losses), and slightly higher starting current.

- 3) High rotor resistance results in high starting torque for line current drawn and slightly lower current during starting, but results in lower full load speed and lower efficiency (high rotor losses).
- 4) The slip at which maximum torque occurs is proportional to rotor resistance.
- 5) Rotor frequency and voltage are proportional to slip. Thus, both are zero at synchronous speed, but increase to a maximum at zero speed (for slip range of 0–100%).
- 6) Rotor I^2R losses are proportional to slip and are in the rotor winding of a squirrel cage motor. On a wound rotor motor, the secondary losses divide in proportion to the inherent rotor winding resistance and any connected external resistance.
- 7) For a pure inertia load (no load torque), the heat energy added to the rotor winding during acceleration (starting) is equal to the kinetic energy of the rotating mass at full speed. The total kinetic energy added to the rotating mass during acceleration to full speed is always the same for a particular value of motor and load inertia regardless of load torque. The effect of load torque is to increase the heat energy added to the stator and rotor windings during acceleration to full speed due to longer accelerating time. The kinetic energy is added to the rotating mass at a rate determined by the accelerating torque (motor developed torque less load torque), and the heat added to the rotor winding is determined by the rotor current and the accelerating time. The accelerating time (and the time the high starting current exists) is inversely proportional to the accelerating torque. Under low-voltage starting conditions, the ratio of heat added to the rotor compared to the kinetic energy at full speed is even greater because the accelerating torque is reduced (developed torque varies approximately as the square of the voltage), the load torque is unchanged, and the ratio of accelerating torque to load torque is reduced (see [12]²²).

11.3.1.2 Ratings of Squirrel Cage Induction Motors

Motor ratings state the basic motor capability in terms of horsepower and speed and indicate the voltage, frequency, and number of phases of the power system to which the motor should be connected.

11.3.1.2.1 Motor Horsepower, Speed, and Voltage Ratings

The standard horsepower, speed, and voltage ratings are contained in Sections 6.1, 6.2, and 6.3 of ANSI C50.41-1982 [1].

Induction motors covered by ANSI C50.41-1982 [1] are rated on a continuous duty basis. The power rating is expressed in horsepower available at the shaft at a specified speed, frequency, and voltage.

The relationship between torque, horsepower, and speed is

$$T = \frac{P_M \cdot 5252}{N}$$

where

T	= torque, in lb.ft
P_M	= mechanical power at the shaft, in hp
N	= speed, in r/min

Induction motors inherently operate at some slip (at a speed less than synchronous speed). The torque at rated horsepower should be determined for the actual speed at rated horsepower.

The preferred motor voltage ratings listed in Table 6.3 of ANSI C50.41-1982 [1] are approximately 4% lower than the typical system nominal voltages from which the motors are supplied, due to anticipated steady state voltage regulation in the power supply system. Table 11.1 lists the typical system nominal voltages for the preferred motor rated voltages.

²²The numbers in brackets correspond to those of the references in 11.2

Other motor rated voltages are usually available for other system nominal voltages.

Table 11.1 – Preferred Motor Rated Voltages for Respective System Nominal Voltages

Preferred Motor Rated Voltage (V)	Nominal System Voltage (V)
460	480
575	600
2300	2400
4000	4160
6600	6900
13200	13800

11.3.1.3 Torque Characteristics

11.3.1.3.1 Torque Definitions

The fundamental characteristic of any induction motor is its speed-torque characteristic. The points of interest on the speed-torque curves (see Fig 11.1) are described as follows:

full load torque: The torque necessary to produce rated horsepower at full load speed. In pound-feet, it is equal to the rated horsepower multiplied by 5252 and divided by the full load speed in r/min.

breakdown torque: The maximum torque that a motor will develop with rated voltage applied at rated frequency without an abrupt drop in speed.

locked rotor torque: The minimum torque that a motor will develop at standstill with rated voltage applied at rated frequency.

pull-up torque: The minimum torque developed by the motor during acceleration from standstill to the speed at which breakdown torque occurs. For motors that do not have a definite breakdown torque, the pull-up torque is the minimum torque developed up to rated speed.

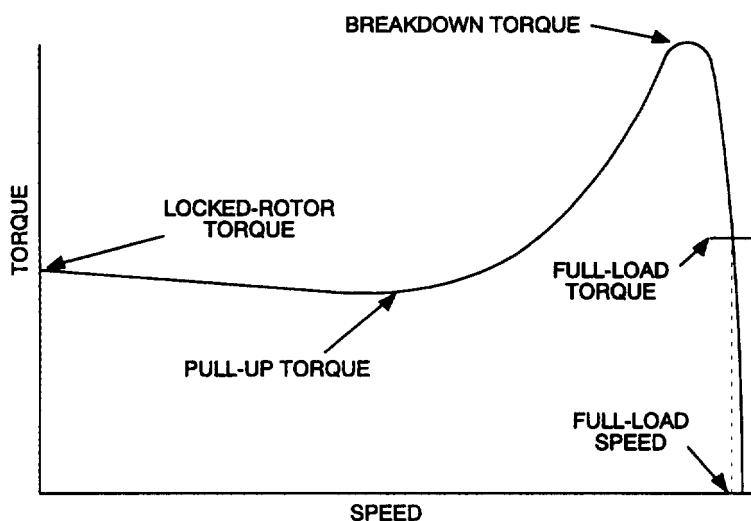


Figure 11.1 – Squirrel Cage Induction Motor Torque Definitions

The electrical industry builds three fundamental types of squirrel cage motors. They are

- 1) Normal starting torque, normal starting current

- 2) High starting torque, normal starting current
- 3) High torque, high slip

11.3.1.3.2 Normal Starting Torque, Normal Starting Current

This is the general purpose squirrel cage motor with normal starting torque and normal starting current. In medium ratings, it is identified as NEMA Design B. The low resistance aluminum (or copper) rotor winding gives low slip (about 0.5–1.5% at full load) and, because of low rotor losses, high efficiency. Normal starting torque falls between 70–100% depending on size and speed. As horsepower rating increases for the number of poles (in other words, for a given speed), the starting torque tends to decrease. Breakdown torque is usually 190% or greater (see ANSI C50.41-1982 [1]) and occurs at relatively low slip. Normal starting current is in the order of 600-650% of full load current. Since the motor has low slip, with the speed variation between no-load operation and full load about 0.5–1.5%, it is generally referred to as a constant speed motor. General characteristics of these motors are shown in Figs 11.2, 11.3, 11.4, and 11.5.

The application for this motor type can be characterized as constant single speed and not very frequent starting duty. Machines such as centrifugal compressors, pumps, fans, and motor-generator sets are typical loads for which this motor is ideal. Modification of the motor design can provide variations in torque characteristics and increased thermal capability required for drives such as high inertia fans.

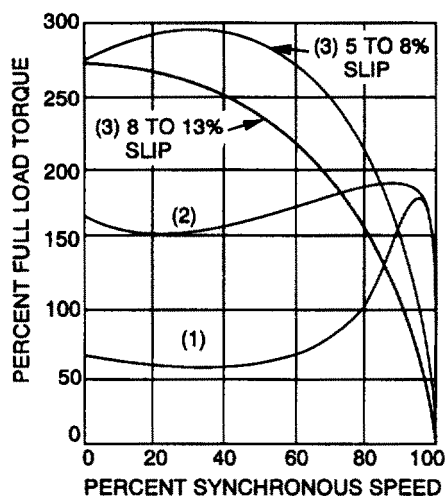


Figure 11.2 — Starting Torque vs. Speed for Squirrel Cage Induction Motors

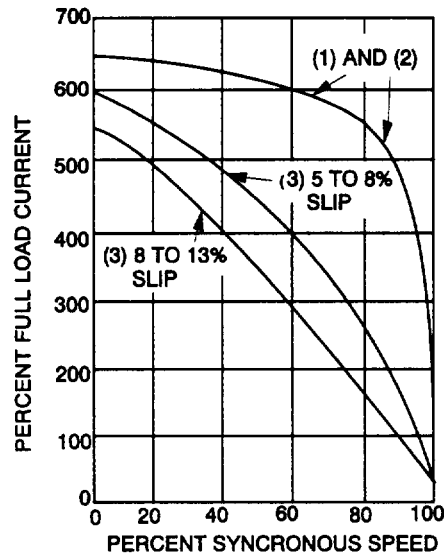


Figure 11.3 – Starting Current vs. Speed for Squirrel Cage Induction Motors

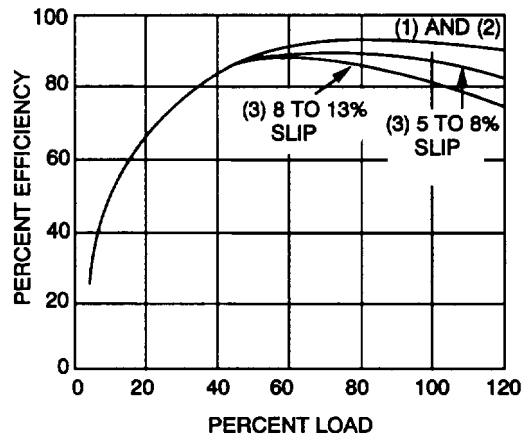


Figure 11.4 – Motor Efficiency vs. Load for Squirrel Cage Induction Motors

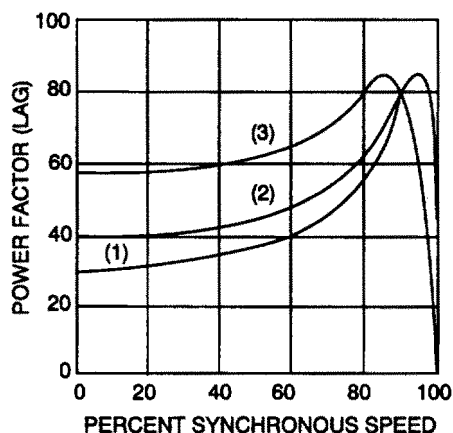


Figure 11.5 — Power Factor vs. Speed for Squirrel Cage Induction Motors

11.3.1.3.3 High Starting Torque, Normal Starting Current

This motor type has high starting torque (about twice full load torque), has normal starting current, and operates at about the same slip at full load as the normal torque motor. In medium ratings, it is identified as NEMA Design C. The characteristics are obtained by the selection of the appropriate shape and resistivity of the bars of the squirrel cage. Generally, this motor will be about as efficient as a standard normal torque motor. See Fig 11.4.

The applications for this type of motor are those that require running characteristics of the normal torque motor but also require high torque during starting. Typical applications include conveyer drives, crushers, and coal pulverizers.

11.3.1.3.4 High Starting Torque, High Slip

This motor type is characterized by a high starting torque, high slip, and low starting current. In medium ratings, it is identified as NEMA Design D. Usual starting torque ranges between 250–300% with a usual value of starting current between 400–600% of full load current. It is also a high slip motor and can be obtained with slips in two ranges: 5–8% or 8–13%. Again, the performance of the motor is controlled by the design of the rotor bars. From the principles listed earlier, it can be concluded that these motors have higher resistance rotor bars and, as a consequence, lower operating efficiency. However, they have the advantage of lower starting current. The higher rotor losses effect the frame sizes of this type of motor, causing the designer to use a larger frame than for other types of motors for a given rating.

Although the high operating slip makes this motor a poor choice for loads requiring constant speed operation, this characteristic makes it extremely useful for applications in which high load torque peaks are encountered or in which load sharing is required, as for tandem drives. An example of the latter is a tandem drive conveyor.

The high slip motor is also used for accelerating fairly high inertia loads, especially when the period of full-speed, full load operation is limited, such as ore or coal car pulling operations or elevator applications.

11.3.1.3.5 Minimum Torque Values

Minimum torque values for normal starting torque and high starting torque motors are listed in Table 3 of ANSI C50.41-1982 [1]. The definitions for normal torque and high torque are presented in 3.1 of ANSI C50.41-1982 [1]. Section 11. of ANSI C50.41-1982 [1] contains additional torque specifications.

When the standard is specified, the motor manufacturer would provide torques that equal or exceed the values listed in the referenced table. The motor manufacturer is not limited by maximum values of torques. For applications such as

conveyors, where high torque levels may be a problem, the limiting maximum values should be specified. Actual maximum values at maximum expected voltage should be considered in foundation design.

11.3.2 Multispeed Motors

The squirrel cage motor is essentially a constant speed machine. Many drives requiring speed adjustment can be handled satisfactorily and advantageously with multispeed induction motors having two, three, or four definite operating speeds.

11.3.2.1 Methods of Providing Multispeed Operation

The various speed combinations are obtained by the following means:

- 1) Single windings
- 2) Superimposed windings
- 3) A combination of (1) and (2)

A single stator winding “consequent pole” motor may be reconnected to give two speeds in the ratio of 2:1. The lower of the two speeds is obtained from the higher speed arrangement by reversing the connections to alternate poles in the stator winding, which, as a consequence, induces additional poles intermediate to the original ones. Doubling the number of poles in this way reduces the synchronous speed of the motor by one-half. The changing of poles is accomplished simply by external reconnection of the six stator terminal leads.

Speed ratios other than 2:1 can be achieved by two methods: the two winding motor or the pole amplitude modulated (PAM) motor. The two winding motor uses two separate stator windings, each wound for a desired synchronous speed. Only one of the windings is connected to the power source at a given time. The two-speed PAM motor has a single winding that is reconnected externally to provide the desired synchronous speed. Combinations of the above methods can be used to obtain multispeed motors with more than two speed ratings.

The physical size of a multispeed motor depends on the required torque capability. In order of decreasing size, they are

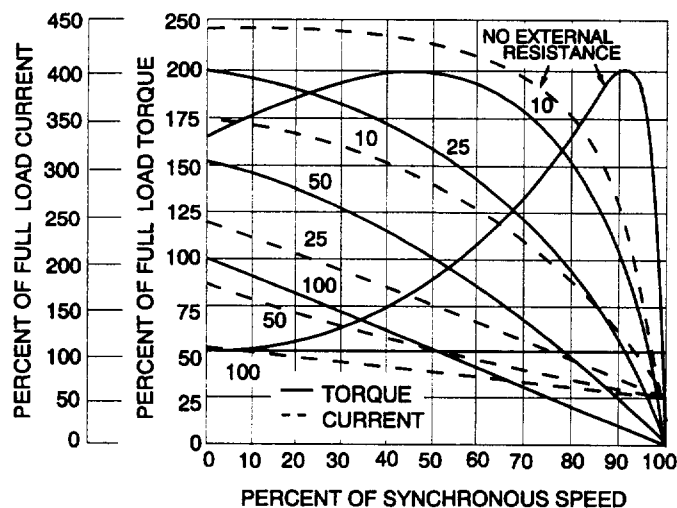
- 1) Constant horsepower
- 2) Constant torque
- 3) Variable torque

11.3.2.2 Horsepower Ratings of Multispeed Motors

The standard methods of arriving at horsepower ratings for multispeed motors are presented in Section 7 of ANSI C50.41-1982 [1].

11.3.3 Wound Rotor Induction Motor

The wound rotor motor is an induction motor with an adjustable speed-torque characteristic. This is accomplished by using a three phase rotor winding similar to the stator winding. One end of each phase is brought out to a collector ring on the motor shaft. Through stationary brushes in contact with collector rings, any desired value of resistance may be added to the secondary circuit. The value of maximum torque (normally between 200–250%) is not affected by change in resistance. But, as is shown in Fig 11.6, the slip or speed at which the maximum torque occurs is dependent upon the secondary resistance. The secondary resistance that results in rated torque at zero speed is known as one per unit ohms or 100% ohms. Similarly, 50% ohms results in rated torque at 50% speed, and 70% ohms results in rated torque at 30% speed. By varying the secondary resistance, it is possible to obtain an infinite number of inrush current vs. starting torque combinations.



NOTE: NUMBERS ON CURVES INDICATE SECONDARY (ROTOR) CIRCUIT RESISTANCE IN PERCENT OF VALUE TO GIVE 100% FULL LOAD TORQUE AT STANDSTILL

Figure 11.6 — Speed-Torque and Speed-Current Curves for Wound Rotor Motors

The adjustable operating speed characteristic of the motor is accomplished by changing external resistance. With considerable resistance in accomplished the secondary, the speed-torque characteristic is sloped back so that speed regulation is poor. Since load current is proportional to torque regardless of external resistance for speeds higher than the speed at which breakdown torque occurs, 100% torque results in 100% current at any speed setting. Were the loss dissipating ability of the motor the same at any speed, the motor would be a constant torque motor. However, due to reduced cooling action, the standard open, 1.0 service factor motor is only capable of 60% torque at 50% speed.

Wound rotor motors are used for very high inertia loads, repetitive starting, or where it is necessary to start with an inrush current limitation lower than that which can be met successfully by a squirrel cage motor or a synchronous motor. Wound rotor motors are reliable drives for centrifugal compressors, variable speed pumps or fans, rolling mills, large ball mills, large presses, and similar applications. They are particularly suited for starting loads with high breakaway torques, such as crushers and ball mills, or for situations in which a high inertia must be accelerated, such as large fans or pumped hydro motor-generators. Wound rotor motors are also used for adjustable speed applications.

Historically, some wound rotor motors have been applied to boiler fans. The most common applications at modern generating stations are coal handling conveyors. Loaded conveyors require high starting torque. At times when the system voltage is low, the motor starting voltage dip for a squirrel cage motor might result in insufficient developed torque. Conveyors can be damaged or can lift off the rollers when unloaded, due to excessive motor starting torque when the system voltage is high. An across-the-line-start squirrel cage motor cannot always meet all of these requirements at some installations. The wound rotor motor with secondary control is ideally suited to this application. External resistors for continuous operation at reduced speed must have greater thermal capability than those applied only for starting. It should not be assumed that a wound rotor motor drive is adequate for reduced speed operation unless the thermal capability of the external resistors is known.

11.3.4 Synchronous Motors (Salient Pole Type)

The synchronous motor is quite similar to the induction motor in its general arrangement; although the synchronous motors normally used in most industries are either very large in rating or quite low in speed relative to the normal induction motor. Typically, the low-speed synchronous motor, used in circulating water pump applications, has a short core length and a large diameter when compared with the induction motor.

11.3.4.1 Principles of Operation

Polyphase synchronous motors have stators and stator windings (armature windings) that are essentially similar to those of induction motors. Similar to the polyphase induction motor, currents circulating through the distributed stator winding produce a flux pattern of alternate north and south poles that progresses around the air gap at a speed directly proportional to the frequency of the power supply and inversely proportional to the number of pairs of poles in the winding.

The rotor of the synchronous motor differs considerably from the induction-motor rotor. The rotor has salient poles corresponding to the number of stator winding poles. During normal steady state operation, the rotor turns at synchronous speed, and there is no average relative motion between rotor pole and the stator flux pole. Therefore, there can be no voltage induced in the rotor by mutual flux, and, hence, excitation cannot come from the ac line. Field coils, with many turns of wire, are wound around the salient poles. The coils are wound so that adjacent poles are of opposite magnetic polarity (north-south-north-south, etc.) when direct current flows in the winding. At one time, the dc excitation had to be applied to the field through brush rigging and collector rings. Today, however, as an alternative, a brushless excitation system with SCR control is frequently used.

Should the rotor be at standstill when direct current is applied to the field winding, the interaction of the stator flux and the rotor flux will provide a large oscillating torque, but the rotor will not accelerate. To start a synchronous motor, then, it is necessary to embed a number of bars in the face of each pole and short circuit these bars at each end to form a squirrel cage similar to that found in the induction motor. Further, the field winding must be disconnected from the dc supply and shorted, usually through an appropriate resistor. By proper design of the size, material, and spacing of the bars in the squirrel cage (often called “amortisseur” or “damper” winding), sufficient induction motor-type torque is developed to accelerate the rotor to nearly full speed. When the rotor has reached sufficient speed, direct current is applied to the field winding, and the motor pulls into step with the rotating stator flux.

11.3.4.2 Ratings of Synchronous Motors

Standard horsepower, speed, and voltage ratings are listed in Sections 21.10 and 21.12 of NEMA MG1-1987 [7].

11.3.4.3 Torque Characteristics

11.3.4.3.1 Torque Definitions

Every synchronous motor must be designed with three different load torque conditions in mind:

- 1) Starting torque to breakaway the load from rest.
- 2) Pull-in torque to accelerate the load to a speed from which the application of dc field will pull it into synchronism. The pull-in torque of a synchronous motor is the maximum constant load torque against which the motor will pull its connected load inertia (WK^2) into synchronism when dc field excitation is applied.
- 3) Pull-out torque to keep momentary overload from pulling motor out of synchronism when a prescribed momentary overload is imposed or voltage dips occur in the power system.

11.3.4.3.2 Standard Torque Values

Standard torques, which vary depending upon motor rating, power factor, and speed, are tabulated in Table 11.2.

Table 11.2 — Minimum Torques at Rated Voltage and Frequency for Synchronous Motors

HP Rating	60 Hz r/min	Percent of Full Load		
		Locked- Rotor Torque	Pull-In Torque*	Pull-Out Torque
For 1.0 PF Motors				
1–200	514–1800	100	100	150
250–1000	514–1800	60	60	150
1250 and larger	514–1800	40	60	150
All ratings	450 and below	40	30	150
For 0.8 PF Motors				
1–150	514–1800	100	100	175
200–1000	514–1800	60	60	175
1250 and larger	514–1800	40	60	175
All ratings	450 and below	40	30	200

Courtesy of General Electric Company

*Based on normal WK^2 load.

11.3.4.3.3 Discussion of Torque Considerations

Although the synchronous motor operates with the dc field of the rotor locked in with the rotating mmf in the stator, it starts and accelerates by virtue of its amortisseur (or squirrel cage) winding, which functions by the same principles as the induction motor. Thus, the starting torque and the pull-in torque (discussed below) vary approximately as the square of the applied voltage, and the starting current varies directly as the voltage, as is the case with the induction motor.

The pull-in torque is defined as the maximum constant load torque against which the motor will pull its connected load inertia (WK^2) into synchronism when field excitation is applied. Since the synchronous motor starts as an induction motor, it will accelerate to the point where the motor torque just equals the torque required by the load. Usually, this point is at 95% speed or greater. When the dc field is applied at the proper point, and the pull-in torque is adequate, the rotor will “pull-in” by accelerating, in a fraction of a revolution, the combined WK^2 of the motor rotor and the load to precisely synchronous speed.

The pull-in torque is primarily a function of the squirrel cage winding characteristics. However, the secondary effect of the external shorting resistor and field winding resistance make important contributions to the speed attainable on the squirrel cage winding with a given load torque applied to the motor. Because of the salient pole effect, the pull-in torque varies somewhat depending upon the angle between the axes of the rotor and stator poles.

The ability to pull-in the WK^2 (that is, pull-in to synchronism) is limited for a given motor. It becomes apparent, then, that for large values of WK^2 , the amortisseur winding must bring the WK^2 to a higher speed than for a small WK^2 . To design for this requires that the value of load torque must be known accurately so that the speed-torque capability of the amortisseur winding can be defined.

For example, consider a high inertia drive such as a fan. The torque required by the fan at full speed is 100% based on nameplate horsepower. Assume, also, that the usual motor does not develop sufficient synchronizing power to synchronize this high WK^2 at any speed less than 98% synchronous speed. The motor must develop sufficient

induction motor torque to accelerate the load to 98% speed or the drive will not pull-in to step when field is applied. (The typical speed-torque curves of Fig 11.8 show how motor torque capability drops as the motor nears synchronous speed.)

In summary, any stated value of pull-in torque must be accompanied by the value of load WK^2 on which the stated value is based. Otherwise, it has no meaning.

The pull-out, or maximum torque (see Fig 11.7), of a synchronous motor is unlike the induction motor breakdown torque in that no speed change occurs until the motor pulls out of step. Since the amount of torque that can be sustained depends upon the strength of the two locked mmf's, any decrease in the strength of either will reduce the torque capability of the motor. Thus, a synchronous motor with a separate dc excitation source, such as an M-G set or a shaft-driven exciter, will have its pull-out torque vary directly in proportion to the voltage change. If the excitation is of the static type that uses the ac supply as its power source, the excitation will also decrease with line voltage drop (unless a constant-voltage transformer or regulating circuit maintains voltage to the static exciter). Since the pull-out torque varies directly with field excitation, the total effect of line voltage variation on the pull-out torque will be proportional to the square of the voltage change. It must be noted that 0.8 pf motors with their larger fields generally have more pull-out torque capability than 1.0 pf motors of the same horsepower and speed.

In the selection of a synchronous motor for a specific application, it is important to know the actual torque requirements. In most cases, the nominal torques tabulated in Table 11.2 should not be specified. The specified starting and pull-in torques should be no higher than necessary inasmuch as increased motor torques result in an increase in starting current, which causes a more severe voltage dip. Some applications require considerably more starting and pull-in torque than the normal standard motor.

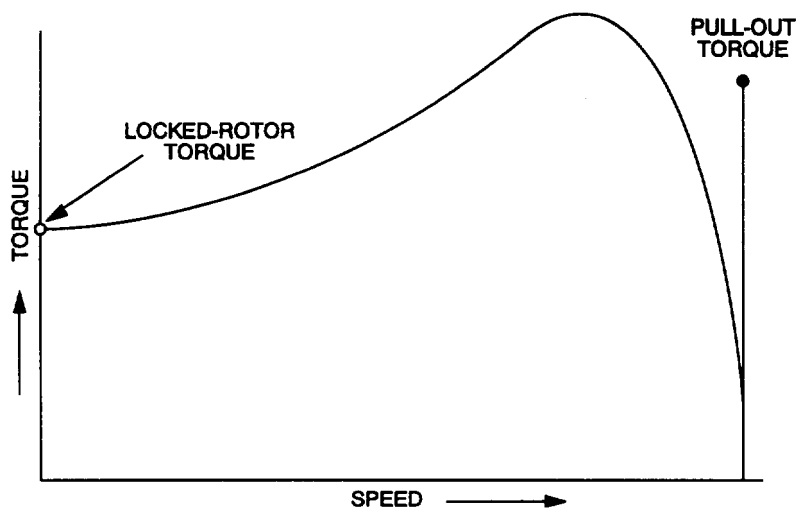


Figure 11.7 — Torque Nomenclature for Synchronous Motors

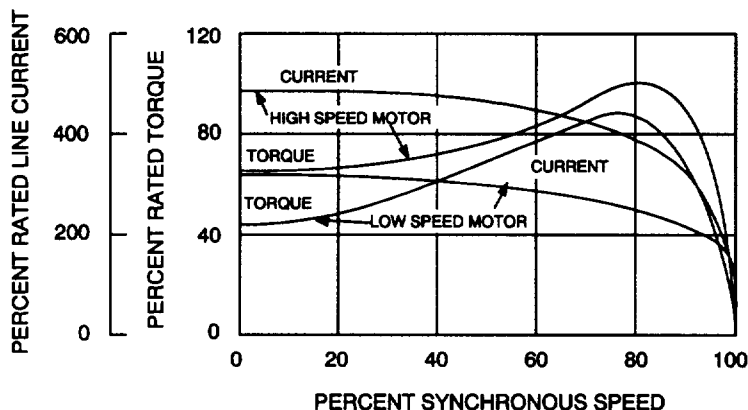


Figure 11.8 – Typical Full Voltage Starting Characteristics for Synchronous Motors

11.3.4.4 Efficiency and Power Factor Considerations

Generally speaking, the cost of a synchronous motor with exciter and control may well prove less than that of any other ac motor if the horsepower rating is equal to or greater than twice the r/min. It is impossible to draw a definite dividing line because various electrical and mechanical modifications (as well as control requirements) enter into the evaluation.

Although the saving in initial cost may be substantial, even greater savings can be realized, in many cases, from the lower operating costs of the synchronous motor. When motor efficiency becomes the primary consideration in choosing a motor, a 1.0 pf synchronous motor is usually the solution. Since no reactive power is required, the line current is a minimum, resulting in less I^2R loss in the motor armature (stator) windings. Also, since the field current required is at the practical minimum, there is less I^2R loss in the rotating field winding as well. Special high-torque situations excepted, the lower losses in both the armature and field usually permit 1.0 pf ratings to be built in smaller frames than corresponding 0.8 pf synchronous motors.

Resulting 1.0 pf synchronous-motor efficiencies are generally higher than induction motor efficiencies for corresponding ratings. Fig 11.9 shows standard full load efficiencies for typical high-speed 1.0 and 0.8 pf synchronous motors and standard squirrel cage induction motors as well. Fig 11.10 is the same display for low-speed motors.

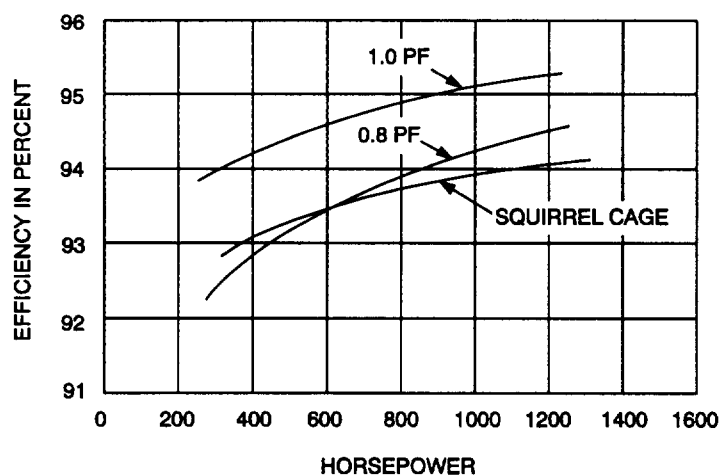


Figure 11.9 – Typical Full Load Efficiencies, High Speed Motors

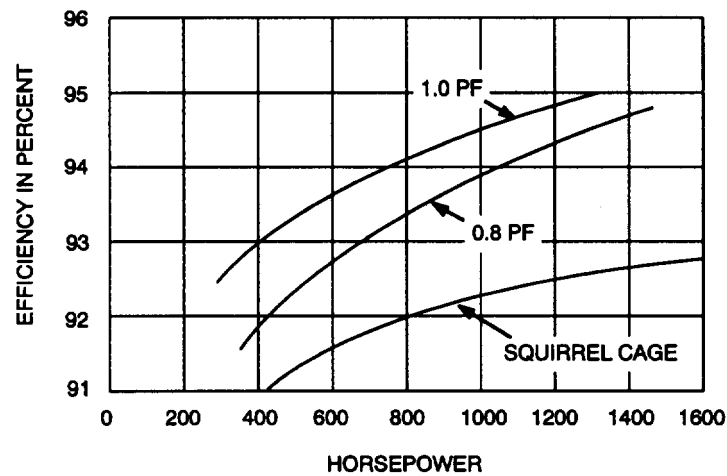


Figure 11.10 — Typical Full Load Efficiencies, Low Speed Motors

Generating station auxiliaries systems have a predominance of lagging power factor loads, such as low-speed induction motors, that require considerable amounts of reactive power in magnetizing (exciting) current. Low power factor indicates an increase in reactive kilovolt amperes (kvar) required and, consequently, an increase in the size of associated power supply equipment. Although it is possible to use capacitors to supply the needed reactive power, if there is an opportunity, it is sometimes preferred to use synchronous motors for this purpose. Because of their separate source of excitation, the load of synchronous motors can be increased without requiring any additional reactive power (the unity power factor motor), or the load can be increased and the motors will supply reactive power as well (0.8 pf or overexcited motor).

Curves shown in Fig 11.11 indicate the amount of corrective reactive power (kvars) provided by both 1.0 and 0.8 pf motors when excitation is held constant and the power required from the motor by the load is decreased. Fig 11.12 displays curves showing how the motor power factor decreases when excitation is held constant and the required horsepower is decreased. The synchronous motor can, in many instances, provide the user with increased power factor while providing the necessary drive horsepower.

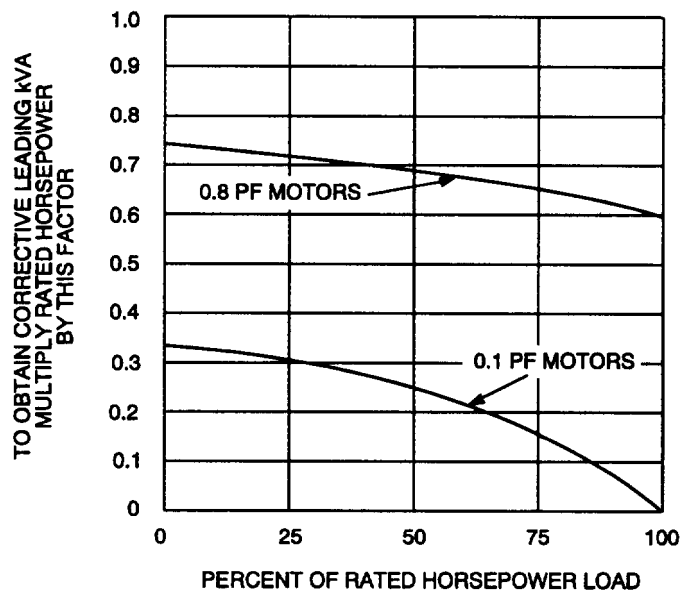


Figure 11.11 — Variation of Reactive kVA With Load for Synchronous Motors

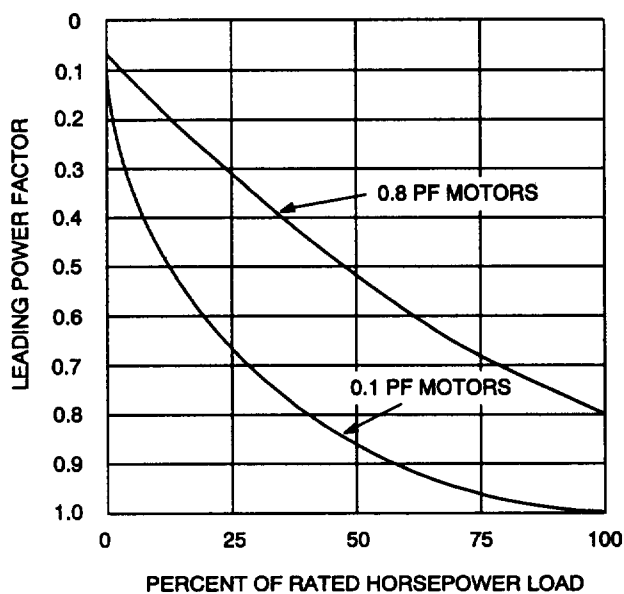


Figure 11.12 — Variation of Power Factor With Load for Synchronous Motors

11.3.4.5 Control and Special Starting Considerations

There are differences in control and motor protection of the synchronous motor, relative to those for induction motors, that are related to the rotor construction. Since the dc excitation is a necessity for synchronous operation, and synchronous operation is fundamental to the synchronous motor, protection against loss of field and loss of synchronism should be provided. During start, the control equipment must automatically and accurately ensure that the rotor speed has reached a proper value and further, in many cases, ensure that the proper angle between rotor and stator flux exists before the dc excitation is applied. “Best angle” field application is more important for high inertia drives. Inasmuch as the synchronous motor squirrel cage winding need only accelerate the load and not produce

running torque continuously, the synchronous motor's squirrel cage thermal capability and, hence, its allowable stall time are generally much less than for an induction motor. However, since the synchronous motor stator windings, bearings, and enclosure variations are essentially the same as for the induction motor, protection schemes for these parts are basically the same.

In addition to considering the effect of load inertia (WK^2) on acceleration into synchronism at near full speed, the motor designer must also consider the acceleration from zero speed to the pull-in point. High load inertia requires high energy input and, consequently, high heat loss in the amortisseur winding. To compensate for this, motors with high inertia loads (five to fifty times normal) are built in larger frames to provide the accelerating capability. Also, as a consequence of high load inertia, acceleration time becomes considerably extended.

Usual requirements during the starting cycle often may be best met by synchronous motors because combinations of special high or low torques and low inrush current can be furnished without appreciably affecting the operating characteristics. Although "normal" starting torque for a low-speed motor is only 40% of full load torque, special design, which affects primarily the amortisseur or starting winding (and sometimes the machine physical dimensions), can provide special high torques. Since only the starting winding is principally affected, normal operating efficiency is only slightly decreased.

The standard synchronous motor with normal torques has a lower starting current than a standard squirrel cage induction motor. However, it must be pointed out that applications involving high starting and pull-in torques and/or high inertia loads require motor designs that, at best, have considerably higher than normal starting current. For example, low-speed synchronous motors applied to condenser circulating water pumps (the most frequent application in generating stations) require high pull-in torque, and the resulting starting current approaches that of an induction motor for the same application.

11.3.5 AC Adjustable Speed Drives

Large ac adjustable speed drive systems are well suited for centrifugal fans, pumps, and compressors. These drives offer several advantages when compared to constant speed drives. The major advantage is high efficiency over a wide load range. Most of the efficiency advantage is associated with speed control of the driven equipment. Speed control to control flow and pressure of centrifugal fans and pumps eliminates the relatively high mechanical throttling losses associated with inlet guide vanes and dampers for fans and throttling valves for pumps. Mechanical speed control devices such as fluid couplings are characterized by relatively high slip losses compared to the low electrical losses of ac adjustable speed drives utilizing static power converters.

11.3.5.1 Load Commutated Inverter Drive System

The load commutated inverter (LCI) or adjustable-frequency synchronous motor drive system is suited to large drives that require a wide speed range. The drive consists of a synchronous motor and a static converter between the power system and the motor stator. A simplified schematic of a six pulse LCI system is shown in Fig 11.13. A simplified schematic of a dual channel effective twelve pulse LCI system is shown in Fig 11.14. The wide speed range capability, relatively high efficiency, and relatively simple inverter make the LCI the most attractive drive system for the majority of auxiliary applications. Each channel of the dual channel system and its corresponding winding of the two winding motor are capable of operating the drive at reduced load while maintenance is performed on the converters of the other isolated channel. Twelve pulse converters generate significantly lower levels of certain harmonics than six pulse converters. The dual channel system, by virtue of the relative phase shifting of the isolation transformers, results in the same levels of harmonics in the power system and drive motor as a twelve-pulse converter system. The LCI drive system can be furnished with regenerative braking capability.

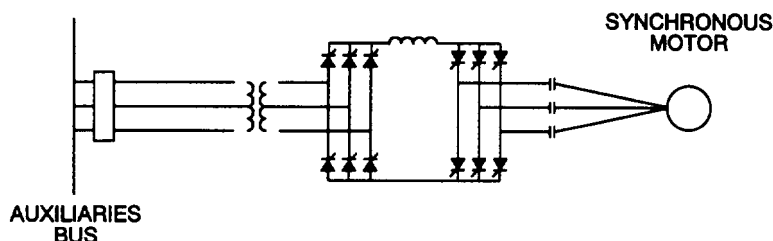


Figure 11.13 — Six Pulse Load Commutated Inverter Drive

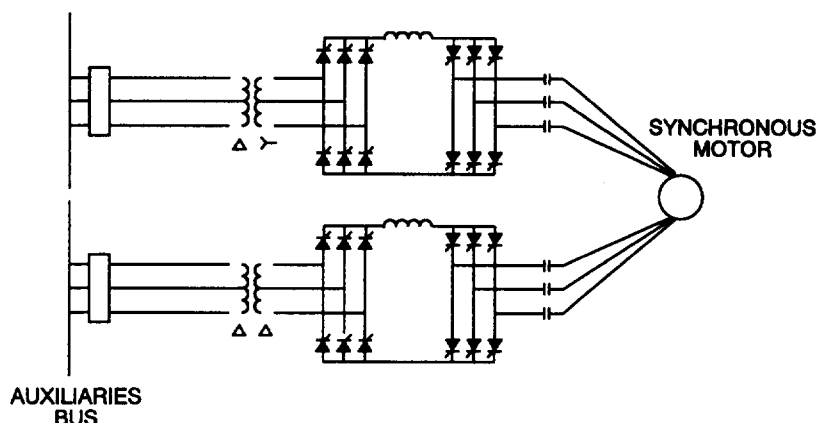


Figure 11.14 — Dual Channel Effective Twelve Pulse Load Commutated Inverter Drive

The LCI drive starting current is dependent on the torque required to accelerate the load. The current is in the order of running load currents. Since the motor is always in synchronism with the power supply, there are no high starting currents that are characteristic of ac motors started across-the-line at full voltage. Therefore, there is no significant voltage dip resulting from the starting of an LCI drive. During system short circuits, the LCI drive does not contribute fault current to the system, except for a low value for a few cycles if the fault should occur during regenerative braking. Some systems allow the static converters to be bypassed when the motor is operated at synchronous speed for the power system frequency. In the bypass connection, the motor will contribute short-circuit current to a system fault.

11.3.5.2 Adjustable Speed Drive for Squirrel Cage Induction Motors

Adjustable speed drives for squirrel cage induction motors are available in several configurations using a number of different converter/inverter technologies. Three of the more commonly applied drives are

- 1) *Variable-voltage inverter (VVI) drive system.* This drive uses a line commutated ac-to-dc phase controlled rectifier, a capacitive filter, and a forced commutated dc-to-ac square wave inverter. The drive is capable of operation over a wide speed range, has low starting current, does not contribute short-circuit current, is not usually capable of regenerative operation, and has low ac input power factor at reduced speed operation. The application range is typically from large integral horsepower machines to 1000 hp. A simplified schematic for a six pulse converter is shown in Fig 11.15.
- 2) *Pulse width modulated (PWM) inverter drive system.* This drive uses a line commutated ac-to-dc diode rectifier, a capacitive filter, and a forced commutated dc-to-ac inverter. The drive is capable of operation over a wide speed range, has low starting current, does not contribute short-circuit current, is not capable of regenerative operation, and has high ac input power factor. The application range is typically from large integral horsepower machines to 500 hp. A simplified schematic for a PWM inverter drive is shown in Fig 11.16.

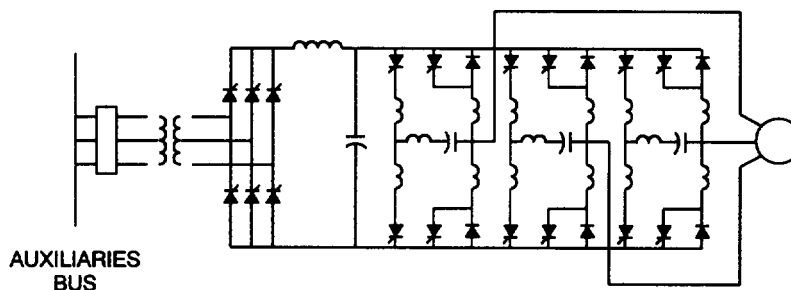


Figure 11.15 – Variable Voltage Inverter Drive System

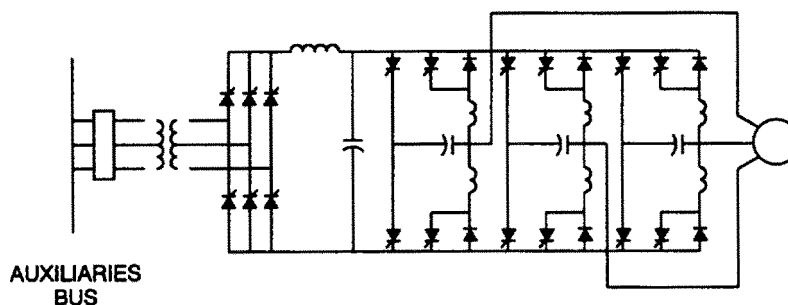


Figure 11.16 – Pulse Width Modulated Inverter Drive System

- 3) *Controlled current inverter (CCI) drive system.* This drive uses a line commutated ac-to-dc phase controlled rectifier, an inductive filter, and a forced commutated dc-to-ac inverter. The drive is capable of operation over a wide speed range, has low starting current, and is capable of regenerative operation. The drive does not contribute short-circuit current, except for a low value for a few cycles if the fault should occur during regenerative operation. The application range is typically from 500–1000 hp. A simplified schematic for a six-pulse converter is shown in Fig 11.17.

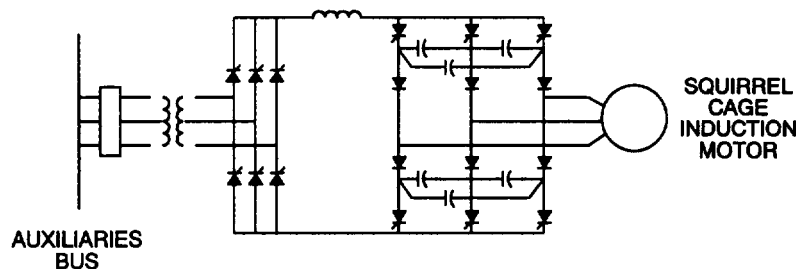


Figure 11.17 – Controlled Current Inverter Drive System

- 4) *Load commutated inverter with dc link diverter.* This drive system is somewhat similar to the LCI system for synchronous machines in that it has thyristor bridges for the line-side phase controlled rectifier and the load-side inverter. It differs from the LCI in that it has a filter with a large capacitor between the inverter and the motor, and it has a diverter circuit in the dc link. A simplified schematic diagram of this drive system is shown in Fig 11.18. The system operates

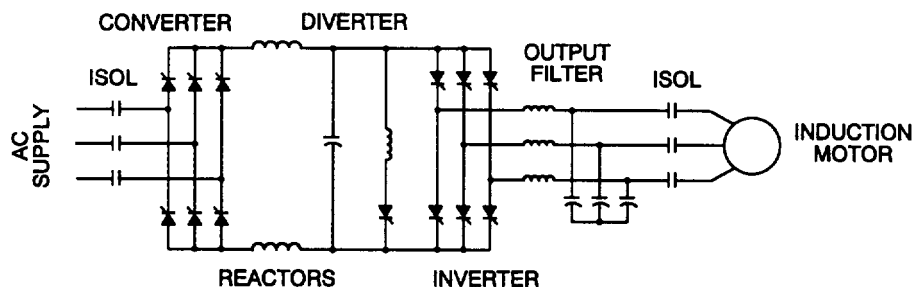


Figure 11.18 — Load Commutated Inverter With DC Link Diverter Drive System With Six Pulse Source Converter

as an LCI in the upper speed range with the filter capacitor providing the reactive power required to excite the induction motor and commutate the inverter. The diverter circuit is required to force commutate the inverter during starting and low-speed operation. This drive system is applied to induction motors in the 500–10 000 hp range and is often applied as a retrofit adjustable speed drive system for existing motors.

- 5) *Gate-turn-off-thyristor current source inverter.* This drive system has a conventional thyristor phase controlled rectifier on the line side and a gate-turn-off-thyristor current source inverter on the load side. It has a large filter capacitor between the inverter and the motor that provides reactive power to excite the induction motor. A simplified schematic diagram of this drive system is shown in Fig 11.19. The gate-turn-off-thyristor inverter is operated in a self commutating mode over the full speed range of the drive. This drive system is applied to induction motors in the 500–10 000 hp range and is often applied as a retrofit adjustable speed drive system for existing motors.

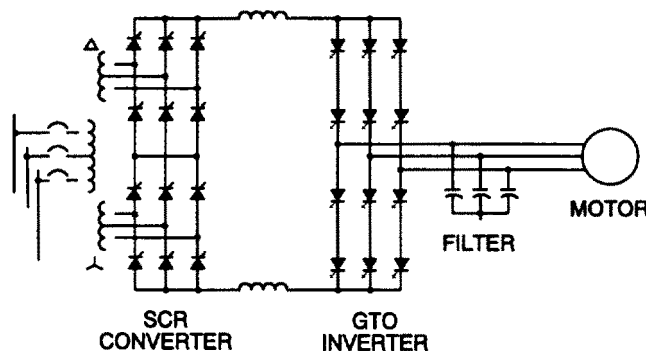


Figure 11.19 — Gate-Turn-Off-Thyristor Current Source Inverter Drive System With Twelve Pulse Source Converter

11.3.5.3 Static Kraemer Drive System

The static Kraemer or slip power recovery drive system is suited to drives that require a limited speed control range. The drive consists of a wound rotor induction motor and a static converter in the rotor circuit. It is a static version of the modified Kraemer drive. A simplified schematic is shown in Fig 11.20. The low-frequency slip power that is normally lost as heat in the secondary resistors

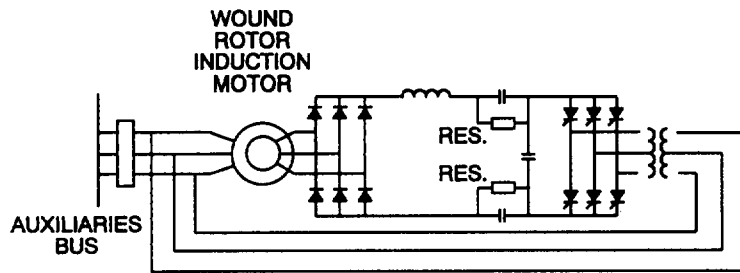


Figure 11.20 – Static Kraemer Drive System

of a conventional wound rotor motor drive is converted back to line frequency. Most of the slip power is then returned to the power system through the inverter isolation transformer.

The static Kraemer drive starting current is dependent only on the amount of torque required to accelerate the load. The current magnitudes are similar to those associated with secondary resistor control of wound-rotor motors. The high starting currents that are characteristic of ac motors started across-the-line at full voltage do not occur when starting static Kraemer drives. Therefore, there is no significant voltage dip resulting from the starting of a static Kraemer drive.

11.4 Integral Horsepower (Medium) AC Motors

11.4.1 General Purpose AC Motor Classification

For power plant application, these motors are polyphase, squirrel cage induction motors in frame sizes 143T through 445T, covering the 1/2–500 hp range at 460 V or 575 V (and, in some power plants, 230 V for the lower part of the horsepower range), three phase, 60 Hz, and are usually rated for continuous service. They are used for all types of constant speed drives, except for those situations where flexibility of application is improved by application of a dc motor. Single phase ac motors may also be used when they are more economical and have acceptable reliability.

11.4.2 Rating Structure

The standardization of motor frame sizes and dimensions, together with performance standards, simplifies motor application and increases motor interchangeability. Certain combinations of horsepower, speed, and voltage ratings are considered standard in the industry.

11.4.2.1 Standard Synchronous Speed Ratings at 60 Hz

The standard synchronous speed ratings at 60 Hz are 3600, 1800, 1200, 900, 720, 600, and 514 r/min. (Required overspeed capabilities are related to the horsepower, speed, and bearing system of the motor. For ac motors, it is typically 20–25%, except that for 200 hp and smaller, below 1200 r/min, it is 50%.)

For details, refer to section 12.48 of NEMA MG1-1987 [7].

11.4.2.2 Standard Voltages

For 60 Hz single phase motors, the standard voltages are 115 and 230 V. For three phase motors, the standard voltages are 230, 460, and 575 V.

11.4.2.3 Standard Horsepower Ratings for Polyphase Integral-Horsepower (Medium) Induction

Motors

The standard horsepower ratings for polyphase integral-horsepower induction motors are 1/2, 3/4, 1, 1-1/2, 2, 3, 5, 7-1/2, 10, 15, 20, 25, 30, 40, 50, 60, 75, 100, 125, 150, 200, 250, 300, 350, 400, 450 and 500. As mentioned before, all horsepower ratings are not available at all speeds.

11.4.2.4 Service Factor

General-purpose motors having a service factor (sf) greater than one are suitable for loading to a value of rated hp \times sf at rated voltage and frequency.

NOTE — The operation above rated horsepower will cause higher temperature rise, and the performance may differ from the performance at rated horsepower. Torque capability will be based on rated horsepower. Also, if a motor is operated continuously at its service factor rating, its expected life will be reduced. (According to the 8–12 °C increase rule, the life of the insulation is reduced by 50% if the temperature is increased by 8–12 °C.) References [1] and [10] contain additional comments regarding service factor.

11.4.3 Polyphase Motors — NEMA Design and Code Letters

11.4.3.1 Design Letters

The design letters relate to permissible starting method, torque-speed characteristics (locked rotor and breakdown torque), and the slip of the motor. Table 11.3 contains torque and slip values for 1800 r/min motors. Fig 11.21 illustrates typical torque vs. speed characteristics of integral horsepower ratings for machines of the various NEMA design letter categories.

The following lists typical applications of various designs:

- 1) A: Centrifugal pumps and motor generator sets — light starting duty
- 2) B: Centrifugal pumps, fans, unloaded conveyor, vacuum pumps
- 3) C: Positive displacement pumps, compressors, loaded conveyors, crushers without flywheels, pulverizers
- 4) D: Car puller, crusher with flywheel, pulverizers, and high inertia drives that do not require high efficiency

Refer also to comments in 11.3.1.3.

Table 11.3 — NEMA Design Letters for Single Speed Polyphase Induction Motors

Design Letter	Torque (% of Full Load)			Starting
	Locked Rotor	Breakdown	Slip (%)	
A	80–275	175–300	<5	FV
B	80–275	175–300	<5	FV
C	200–250	190–200	<5	FV
D	≥275		≥5	FV

NOTE: The above values are representative values for 1800 r/min motors. They are functions of both the horsepower and speed ratings of the motor. Sections 12.38 and 12.39 of NEMA MG1-1987 [7] contain tables of torque values for various horsepower and speed ratings.

Design A is used where high efficiency and high full load speed are required.

Design B is the general purpose motor suitable for pump and fan drives.

Design C is the high starting torque motor with almost constant torque values throughout the entire speed range.

Design D has higher starting torque than Design C. It is to be noted that this design results in high running slip; therefore, motor efficiency is lower.

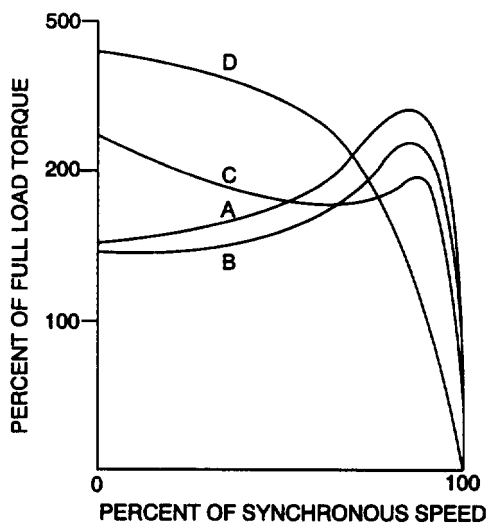


Figure 11.21 — Integral HP Induction Motor Torque vs. Speed Characteristics for Design Letters A, B, C, and D.

11.4.3.2 Locked Rotor Indicating Code Letters

Locked rotor indicating code letters, stamped on the motor nameplate, indicate the range of starting kVA/hp.

They are capital letters of the alphabet, A through V. Values of locked-rotor kVA per horsepower for each of the code letters are listed in section 10.37 of NEMA MG1-1987 [7].

The full-voltage, rated frequency, locked rotor current can be estimated from the value of the locked rotor indicating code letter (kVA/hp) as follows:

$$I_{LR} = (\text{code letter value}) \cdot \frac{hp}{\sqrt{3}kV_{NP}}$$

where

$$\begin{aligned} hp &= \text{nameplate horsepower rating} \\ kV_{NP} &= \text{nameplate voltage of the motor, in kV} \\ I_{LR} &= \text{locked rotor current, in A} \end{aligned}$$

The approximate per unit motor starting impedance (Z_s) on the motor kVA base can be calculated from the known code letter, horsepower rating, full load efficiency, and power factor (the latter two are in per unit values):

$$Z_s = \frac{1}{\text{code letter value}} \cdot \frac{0.746}{\text{eff} \cdot \text{pf}}$$

The locked rotor power factor can be estimated from Fig 11.22 for locked rotor voltage drop calculations.

The kVA base is equal to $\sqrt{3} \cdot \text{rated kV} \cdot \text{full load current}$.

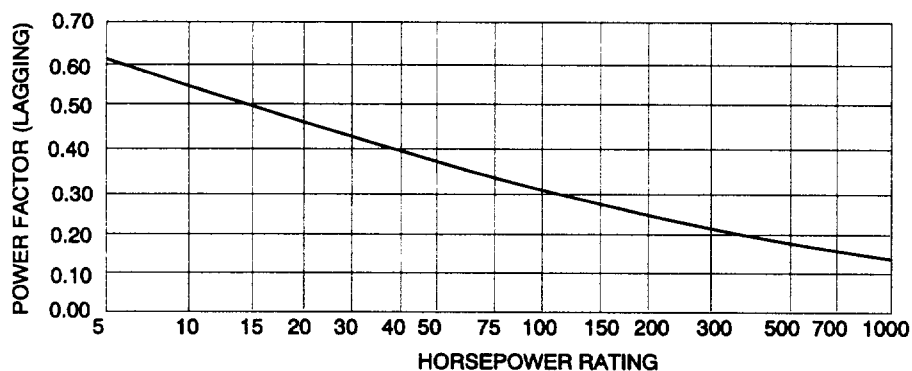


Figure 11.22 — Approximate Starting Power Factor of Typical Squirrel Cage Induction Motors

11.4.4 Temperature Rise for Integral HP (Medium) AC Motors

Standard values of maximum allowable winding temperature rise for maximum ambient temperature of 40 °C are listed in Section 12.43 of NEMA MG1-1987 [7].

11.5 DC Motors

Power plant applications include steam turbine governor drives and emergency lube oil and seal oil pumps for the turbine and generator, respectively. The horsepower ratings range from fractional to 50 hp. In rare cases, motors in excess of 50 hp may be required.

11.5.1 DC Motor Types

Construction of dc motors is basically different from polyphase induction motors. In a spatially stationary magnetic field, a current carrying conductor loop rotates by interaction with the stationary field and the field generated by the conductor current.

For power plant applications, most dc motors are shunt wound. The rotor windings of shunt, series, and compound dc motors are the same for all types. Shunt-wound dc motors have an overspeed capability of 25% above the highest rated

speed or 15% of the no load speed, whichever is greater. Loss of field power to a shunt motor results in excessive overspeed.

The stator windings are basically field windings connected as follows:

- 1) *Shunt motor*: shunt main poles, commutating and compensating poles
- 2) *Series motor*: series main poles, commutating and compensating poles
- 3) *Compound motor*: shunt and series windings on the same poles, commutating and compensating poles

The torque vs. speed characteristics depend on the interaction of armature and fields, as shown in Fig 11.23.

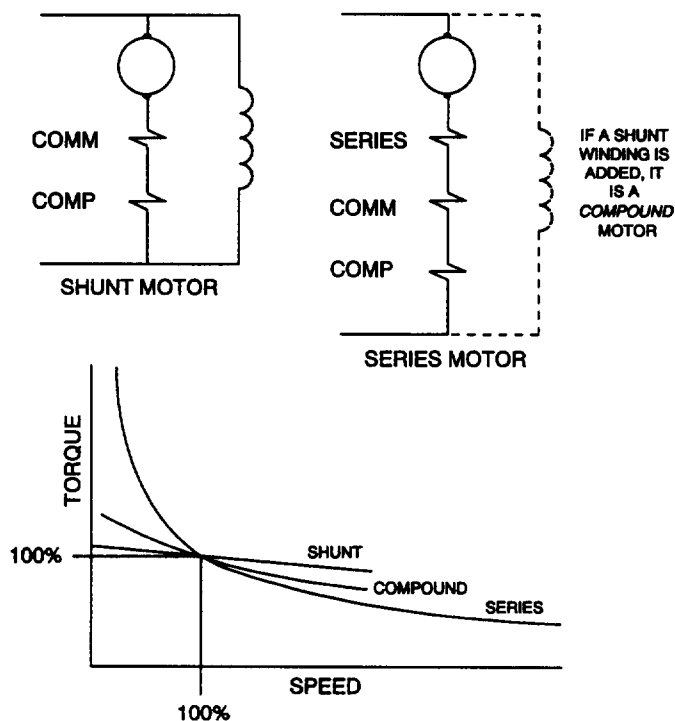


Figure 11.23 —DC Motor Torque vs. Speed Characteristics

11.5.2 DC Motor Performance Relationships

The basic equations are:

$$E_m = C_1 \Phi N \quad (11.1)$$

$$V_m = E_m + I_A R_A = C_1 \Phi N + I_A R_A \quad (11.2)$$

$$N = \frac{V_m - I_A R_A}{C_1 \Phi} \quad (11.3)$$

$$T = C_2 \Phi I_A \quad (11.4)$$

where

- E_m is the counter emf generated by the motor.
- N is the speed in r/min.
- Φ is the flux generated by the poles.
- C_1 and C_2 are constants derived from the motor design.
- I_A and R_A are the armature current and resistance, respectively.
- V_m is the voltage applied to the motor terminals.
- T is the motor torque.

Eq 11.2 states that, at zero speed, $V_m = I_A R_A$. Since R_A is very low, I_A may be extremely high.

Eq 11.3 shows the modes of speed control: V_m could be varied. This has the same effect as increasing the armature resistance. Main flux, Φ , can be varied. In case of a shunt motor, it is very convenient to control the flux with the 1–4% field energy.

Eq 11.4 describes how the motor torque is developed. It also explains why the armature current must be controlled. At start, extremely high torques could be developed. Industry practice is usually to limit the armature current to 2.0 pu. In the emergency lubrication service, where fast starts are required, the armature current is limited to 3.5–5 pu.

11.6 AC Motor Applications

11.6.1 Motor Selection Factors

- 1) *The physical environment*: temperature, humidity, precipitation, presence of dusts, fumes, gases, humidity, salt, etc.
- 2) *The electrical environment*: power system capacity, system grounding, variation of voltage and frequency, steady state and short-time transients.
- 3) *The duty cycle*: continuous, intermittent (start, run, and stop with the same load), or variation of both load and time of operation.
- 4) *Torque requirements*: interaction of driven equipment and its controls with the electric driver; investigation of inertias and required starting time; and forces, torques, vibration, etc., that are transmitted by driven equipment to the motor.
- 5) *Orientation of motor mounting*: horizontal, vertical, method of coupling, etc.
- 6) *Accessories needed*: motor space heater, grounding pads, winding and bearing temperature detectors, vibration detectors, filters, guards, and sound suppression.
- 7) *Bearings*: antifriction vs. sleeve and thrust requirements.

Table 11.4 – Comparison of DC Motor and Polyphase AC Induction Motor

	Squirrel Cage Induction Motor	DC Motor
Stator body	Laminated	Cast steel with laminated stationary poles (main commutating, compensating)
Stator winding	Three phase carries the line current	Field: shunt, series* (these produce torque); commutating*, compensating* (these aid commutation)
Rotor	Laminated	Laminated
Rotor winding	Uninsulated squirrel cage	Insulated to the line voltage, carries the line current
Commutator	Not needed	Admits the line current to loops selected by the brushes

*These windings carry line current

11.6.1.1 Service Conditions

Usual and unusual service conditions for integral horsepower (medium) ac motors are listed in Sections 14.02 and 14.03 of NEMA MG1-1987 [7]. Usual and unusual service conditions for large ac motors are listed in Section 4. of ANSI C50.41-1982 [1].

11.6.2 Pump Drive Applications

11.6.2.1 Centrifugal Pump Drives

Selecting drive motors for direct connection to centrifugal pumps for general applications is usually straightforward. The WK^2 of the centrifugal pump is usually so small (compared to the normal values in the standards) that it may be ignored in the normal squirrel cage induction motor application. (The pump inertia should not be ignored for synchronous motor applications.) The torque of a centrifugal pump typically varies with the square of the speed. For preliminary application considerations, the pump torque is assumed to be equal to the full load torque of the motor at rated speed, and the torque decreases with the square of the speed down to a very low value at 10 % speed. It usually is assumed that the curve rises sharply from about 3 or 4% speed up to about 25-30% torque at zero speed. This higher torque near standstill represents the static friction in the stuffing box and in the pump bearing and is probably greater than the actual requirement. But, since it is not usually a critical part of the application, such assumptions are normally made.

Normal torque squirrel cage motors built in accordance with ANSI C50.41-1982 [1], develop at least 70% starting and pull-up torque. From approximately 70% speed, the motor torque curve rises quite rapidly, and there usually is no problem in selecting the motor if the voltage holds up reasonably well while the motor is accelerating.

If the motor is to be started at reduced voltage, the actual motor speed torque curve for reduced voltage should be determined, using the minimum voltage that will actually exist at the motor terminals during starting. The assumed speed-torque curve of the pump, based on full load torque and full speed, should be plotted against the motor curve. If there is not at least ten percentage points of torque margin (based on full load torque) of the motor curve over the pump curve, the application should be checked carefully. Eventually, the actual speed-torque curve of the pump should be obtained.

For reduced voltage starting, it may be possible to start with the discharge valve closed, which, in the case of a true centrifugal pump, will reduce the load torque during acceleration. If it is planned to use this procedure in starting, a speed-torque curve of the pump with the discharge valve closed should be obtained from the pump manufacturer, and the motor and pump characteristics should be checked carefully. If the pump is started with the discharge valve closed, it must be opened quickly when the motor comes up to speed. The pump cannot operate more than a minute or two with the discharge valve closed without excessive heating, even though the pump is full of water, because all of the energy that the motor is delivering to the pump is converted to heat inside the pump. The pump heats up very rapidly, and it will soon cause mechanical difficulty if the discharge remains closed.

When making a study on the basis of starting with the pump discharge valve closed, be sure to determine if the pump is a true centrifugal pump. If so, the estimated torque required to drive the pump with the discharge valve closed is approximately in the range of 50-60% of full load torque. A speed torque curve of the pump under the closed valve conditions should be obtained from the pump manufacturer. Pumps that are not truly centrifugal, such as mixed flow pumps, may actually require more torque to drive the pump at full speed with the discharge valve closed than with the valve open. Axial flow pumps, in nearly every case, require appreciably more torque (sometimes in the neighborhood of 200% torque) to drive them to full speed with the discharge valve closed. It is very important to know the actual characteristics of the pump under both open and closed valve conditions. Further considerations in the case of vertical pumps are the thrust requirements for the thrust bearings that are usually located in the motors. Thrust requirements are different for starting, operation, and shutdown. With positive displacement pumps, it is impossible to start with a discharge valve closed because each revolution of the pump shaft displaces a certain amount of water and there must be some place for this water to go.

When the valving of several pumps working into a common header is so arranged that a deenergized pump motor may rotate in the reverse direction, either a ratchet coupling is required, or the motor must be capable of accelerating the pump from reverse rotation.

Fig 11.24 shows typical speed-torque curves of a 2000 hp, 3600 r/min, 4000 V squirrel cage motor. Curve A represents torque at full voltage

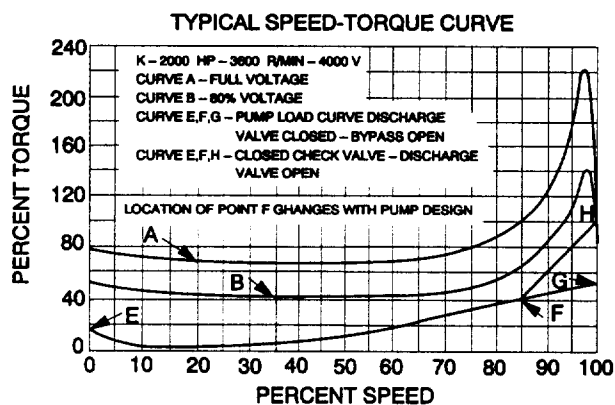


Figure 11.24 — Typical Torque vs. Speed Characteristics for Squirrel Cage Motor at 100% and 80% Voltages and Boiler Feed Pump

conditions. Curve B represents torque at 80% voltage conditions. If the motor is driving a boiler feed pump, there will be a check valve in the discharge of the pump to prevent water from flowing back from the boiler through the pump while it is not operating.

When the motor starts and the pump accelerates to full speed, the pump will be operating along a closed discharge valve curve EFG, as shown in Fig 11.24. When the pump pressure equals the boiler pressure or the pressure in the water system, the check valve opens (point F), and the speed-torque curve now rises rapidly to point H as the pump begins to deliver water and approaches full capacity at full speed. The point F at which the check valve opens varies with the pump design and, in extreme cases, may be as low as 70% speed. Usually, it is in the range from about 78-93% speed. For 80% voltage start (referring to Fig 11.24), if the check valve should open at 70% speed, the motor curve at reduced voltage and the pump curve would practically intersect at about 85-87% speed. Since this would not provide the required torque margin to permit the motor to accelerate up to speed in a reasonable length of time, it would be necessary to provide a special motor with higher developed torque during starting.

In some cases, it is possible to raise the torque curve of the motor in the range from 70-90% speed by a slight sacrifice in full load speed and efficiency.

Fig 11.25, Curve B, shows motor torque while starting with 65% voltage at the motor terminals. Note that the motor curve and pump curve are very close together at approximately 80% speed so the rate of acceleration would be so slow that the motor would probably overheat. This particular design, therefore, is not suitable for starting this load at 65% voltage. Again, a special motor design would be required if it was required to start the pump at 65% voltage.

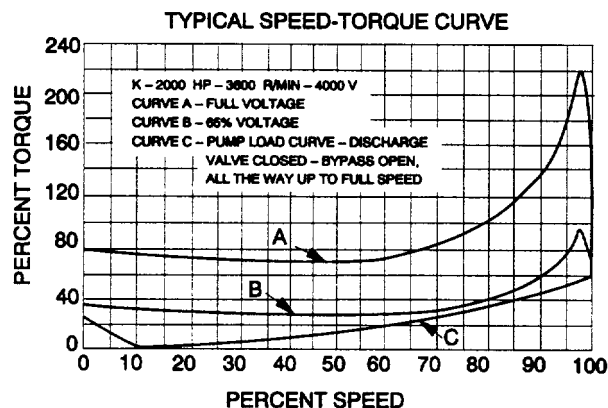


Figure 11.25 — Typical Torque vs. Speed Characteristics for Squirrel Cage Motor at 100% and 65% Voltages and Boiler Feed Pump

11.6.2.2 Axial-Flow Pumps

Axial-flow pumps are used for handling large volumes against relatively low heads. Axial-flow pumps have a characteristic that enables them to maintain an almost constant flow with a wide change in discharge head. This makes them particularly suited for supplying circulating water to condensers that require a constant flow of water under all conditions. These pumps frequently take water from rivers where the river level will vary widely at different seasons of the year, and the design of the pump is such that it will supply practically the same amount of water whether the river is high or low. Because of this characteristic of the design, the torque required to drive the pump with the discharge valve closed will be higher than that required to drive the pump with the discharge valve open. Usually, these pumps are never started with the discharge valve closed. However, if the unusual condition is encountered in which the motor must be capable of starting the pump with the discharge valve closed, it is necessary to determine the torque required under this condition. Fig 11.26 shows a typical requirement in which the torque required to drive the pump with the discharge valve closed is 175% of full load torque. In some cases this torque may actually be as high as 200% or 300% of normal full load torque.

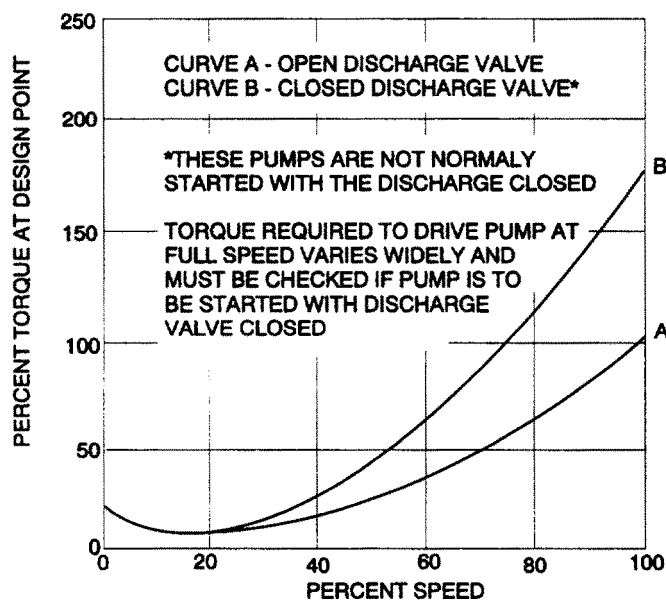


Figure 11.26 — Typical Speed-Torque Curve for Axial Flow Pumps

11.6.2.3 Mixed-flow Pumps

Mixed-flow pumps are a combination of axial-flow and centrifugal pump characteristics and are used for intermediate lifts and relatively large volumes of water. One of the characteristics of this type of pump is that it tends to maintain a constant flow of water even with change in discharge head. Because of this characteristic, the torque requirement to drive the pump at full speed with the discharge valve closed is appreciably higher than the torque required to drive a true centrifugal pump. Fig 11.27 shows a speed-torque curve of the pump with the discharge valve open and also with the discharge valve closed. Curve *B* shows a torque requirement of 120% to drive the pump at full speed with the valve closed. However, this value may vary quite widely with the design of mixed-flow pumps. When applying a motor that is to drive a mixed-flow pump with the discharge valve closed, the torque required by the pump should be determined before a motor selection is made.

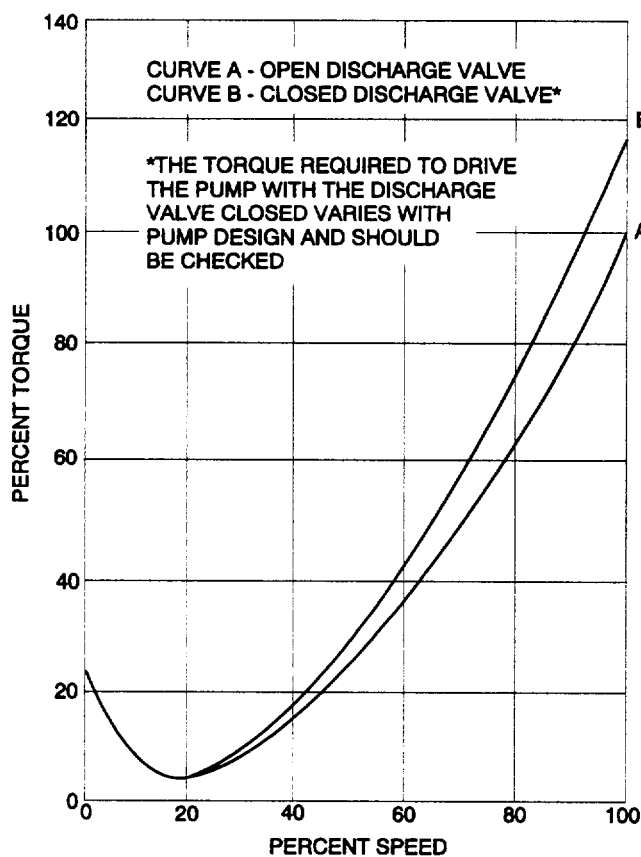


Figure 11.27 — Typical Speed-Torque Curve for Mixed Flow Pumps

Frequently, mixed-flow (and axial-flow) pumps are started with the discharge valve closed. However, as the pump accelerates, the discharge valve is opening. By the time the motor reaches full speed, the pump torque requirements may not be those of curve B (Fig 11.27), but may be those of curve A. Even if the valve requires a few seconds longer to open than the motor does to accelerate, there may not be a problem if there is sufficient torque to continue acceleration due to voltage recovery as the motor accelerates. Pump torque at full speed is of special significance with synchronous motors because they must pull-in to synchronous operation against the load torque. Pull-in torque is a very significant factor in the application of a synchronous motor (see 11.3.4.3.3). It is apparent, then, that for mixed and axial flow pump applications, it is necessary to know not only the two speed torque curves, but also the opening time of the discharge valve.

11.6.3 Fan Drive Applications

Squirrel cage induction motors, synchronous motors and wound rotor induction motors are all used for driving fans. Squirrel cage induction motors are used most often for driving fans in generating stations. Typically, centrifugal fans have inertias several times the NEMA normal load inertia for squirrel cage induction motors. As a result, a special squirrel cage rotor design and larger-than-normal frame size is often required. Axial fans tend to have inertias lower than centrifugal fans.

Synchronous motors are less frequently applied to fan drives. The typical synchronous motor has significantly less capability for accelerating high inertia loads than the typical induction motor. Synchronous motors for a fan drive are virtually always of special design, and the application should be referred to manufacturers for consultation. The NEMA normal inertia values for synchronous motors are small fractions of the normal values for induction motors. Fans have inertias in the order of 40–50 times the NEMA normal inertia for synchronous motors.

Wound rotor induction motors with secondary resistor control can be applied because a major portion of the acceleration losses with this type of motor are dissipated in the external secondary resistance. In addition, the wound rotor motor may be used to provide adjustable speed and, hence, adjustable flow. The wound rotor is the most suitable motor for accelerating very high inertia loads.

Fluid couplings are used occasionally to connect squirrel cage induction motors to fans. When a fluid coupling is used between the motor and the high inertia fan, standard motors and controls are often suitable, provided that the fluid coupling allows the motor to accelerate to full speed before the fan is accelerated. The coupling must be arranged to allow removal of the fluid from the coupling when the drive is stopped, so that a standard motor will never have to accelerate itself and a high inertia fan at the same time.

The load commutated inverter (LCI) adjustable speed drive system (see 11.3.5) is an excellent drive for boiler fans. An increasing number of these drives are being applied for this application. The high efficiency of the drive system complements the high mechanical efficiency obtained with adjustable speed flow control. The LCI soft start eliminates the severe motor duty associated with across-the-line starting of high inertia fans. The energy and capacity savings that result from the high efficiency usually compensate for the relatively high initial investment by a wide margin. Adjustable speed fan drives that operate over wide speed ranges require a torsional analysis of the motor-coupling-fan system to determine if damaging torsional oscillations could occur. In such cases, resilient couplings can be applied to change the torsional characteristics.

Application considerations when applying constant speed motors to fan drives include

- 1) Inertia of the fan referred to the motor shaft
- 2) Speed-torque curve of the fan referred to the motor shaft
- 3) The frequency of starting for the particular drive
- 4) Voltage conditions existing at the drive-motor terminals during start
- 5) Ambient conditions
- 6) Torsional vibration characteristics of the combined motor-fan system

The load inertia (or WK^2) of the fan, the torque characteristic of the fan, and the motor terminal voltage during a start are major factors that determine the ability of a fan drive to accelerate to full speed. They also determine the motor heating during a start, which is a major consideration for fan drives. Typical torque vs. speed characteristics for an induced draft fan and a forced draft fan are shown in Figs 11.28 and 11.29. For any given inlet guide vane or damper position, and any given gas temperature, the fan torque varies as the square of the speed. For centrifugal fans, as with centrifugal pumps, less torque is required for closed discharge as compared with open discharge. Similarly, cold gas requires more torque than hot gas. Many fans are started with the vanes or dampers closed, which reduces the thermal duty on the motor during starting and reduces the accelerating time. These principles also apply to primary air fans. Repetitive starting duty requirements can be quite severe during initial plant testing and plant startup following extensive maintenance. Requirements should be carefully considered, and instructions concerning motor limitations should be followed rigorously.

Motor torque varies approximately as the square of the applied voltage, so it is necessary to check the power system to determine the voltage drop caused by the motor locked rotor current. Before completing the final design, the motor designer must be informed of the actual voltage at the motor terminals during starting.

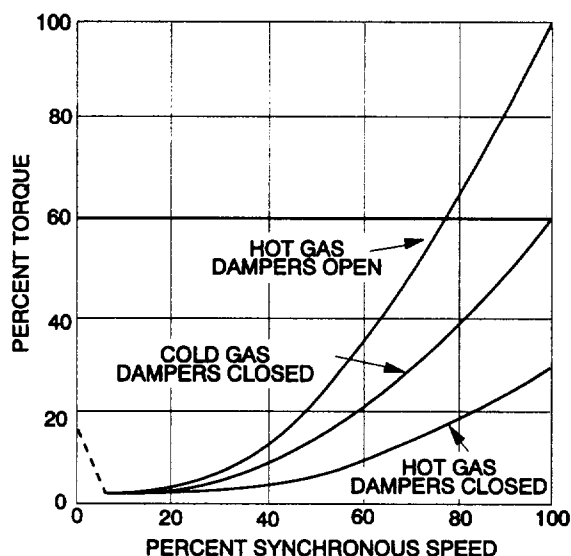


Figure 11.28 — Typical Speed-Torque Curve for Induced Draft Fans (Centrifugal)

If it is desired to start on reduced voltage, it is necessary to determine the method to be used and the system voltage drop to arrive at the actual voltage at the motor terminals. Since fan inertias are high, the motor speed-torque curve at the reduced voltage available at the motor terminals should be plotted together with the fan speed-torque curve. For a fan drive in which the load inertia is high, there should be a minimum of 15 percentage points of motor torque available between the motor curve and the fan curve (at any point on the curve) to assure acceleration. Prolonged acceleration will cause overheating of the motor. For very high inertia drives, the minimum accelerating torque may need to be much greater than 15%. This determination should be made by the motor designer.

It is also necessary to determine the ambient conditions, such as dirt and contaminants, exposure to weather, or the presence of explosive vapors and the nature of the explosive condition. A suitable insulation system and/or enclosure should be selected to meet the environmental conditions.

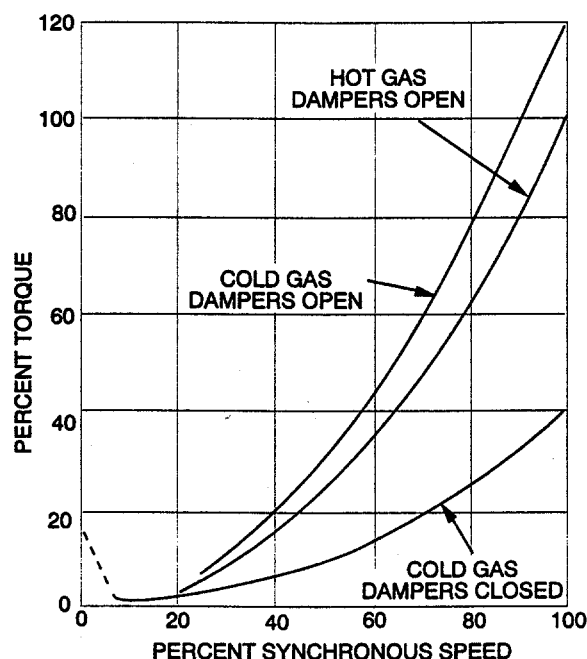


Figure 11.29 — Typical Speed-Torque Curve for Ventilating and Forced Draft Fans (Centrifugal)

11.6.4 Coal Pulverizer Applications

Coal pulverizer types are, from a motor application standpoint, characterized by the load inertia reflected back to the drive motor shaft.

Low inertia pulverizers have breakaway torque requirements in the order of 175% of rated motor torque. During the acceleration period, the load torque may be equal to 100% of full load torque at rated speed. While it would be desirable to empty the pulverizer prior to stopping the drive, or prior to subsequent starting of the drive, practical considerations often dictate that the driving motor must be selected on the basis of starting and accelerating a loaded pulverizer to full speed. The values of WK^2 usually are within the NEMA normal value for these drives.

Attrition-type pulverizers are a high inertia type mill whose reflected WK^2 is greatly in excess of the NEMA standard load WK^2 . These pulverizers, therefore, require a drive that will dissipate the heavy slip losses, due to the long acceleration period, external to the drive motor. Such a drive normally consists of a squirrel cage motor coupled to the pulverizer through a special slip clutch. These coal pulverizer drives require motors tailored to the actual requirements.

11.6.5 Horizontal and Vertical Motor Application Considerations

The horizontal motor is much simpler in construction than a vertical one. The horizontal motor has limited capability for axial forces transmitted from the driven equipment. For machines with anti-friction bearings, thrust capability can be increased by using angular contact ball bearings or double spherical roller bearings. Vertical motors can be of the hollow or solid shaft design. These motors usually carry sizable axial loads. These axial loads consist of the weights of the pump, shaft, water in the suction and discharge pipe, and the axial thrust due to pressure. The anticipated axial loads (thrusts) should be carefully specified.

The thrust bearings are of elaborate design. One type is the tilting pad thrust bearing. These types of bearings require large quantities of lubricating oil and may sometimes require cooling of the oil. (Refer to 11.15.)

The hollow shaft motor is coupled to the driven equipment shaft at the top of the motor.

11.6.6 Motor Operated Valve Applications for Integral Horsepower AC Motors

A generating unit may have several hundred motor operated valves. Their functioning is important because

- 1) Some valves are used to open or shut certain pipe lines, pumps, etc. These are two position valves. Typically, they are gate, butterfly, and globe valves.
- 2) Some valves modulate or regulate the flow. These usually are globe valves because their friction head loss is less.
- 3) These valves handle fluids (water for different uses), vapor (as steam), and gasses (compressed air, etc.).
- 4) Valves are either essential or nonessential. Essential valves are the ones required to function for the safe shutdown of the unit, to prevent extensive economic losses, and to protect human life. Such valves, if not able to operate, may also cause the forced shutdown of the unit. Nonessential valves are not required to operate for safe shutdown, and failure to operate does not result in severe consequences.
- 5) The motor operators are ac squirrel cage induction or compound dc motors.

AC motor drives have high torque, high slip motors with typical rated short time duty of 15 min. A valve has two extreme limits of travel, full open and full close. Typically, a valve motor actuator will have built-in position limit switches to stop the unit at the full open and full closed positions and to indicate its position.

In addition to position limit switches, actuators are equipped with a torque limiting device. This device is designed to limit the output torque of the actuator to the peak torque required by the valve to seat or unseat it. The torque limiting device cannot protect the assembly, including the motor, against loads less than its set position, which is the peak torque.

11.6.6.1 Valve Torque Requirements

Most motor actuated valves have a stroking time, full open to full close, of less than two min. There are numerous valve designs, each of which has its own torque requirements. Typical wedge gate valves require torque as shown in Fig 11.30. The maximum load on the motor represents the valve unseating torque and is provided by the starting torque capability of the motor.

Typical globe valve torque requirements are shown in Fig 11.31. Maximum torque on the motor also represents the valve unseating, assuming the pressure is over the disc/plug and is achieved using the starting torque capability of the motor.

Butterfly valves experience two different extremes of torque requirements. For the valves used in low fluid velocity systems (Fig 11.32) requiring tight shut-off, the typical torque requirements are similar to wedge gate valves in that the predominant requirement is seating or unseating. In these applications, the stall or starting torque capability of the motor is used to achieve seating or unseating.

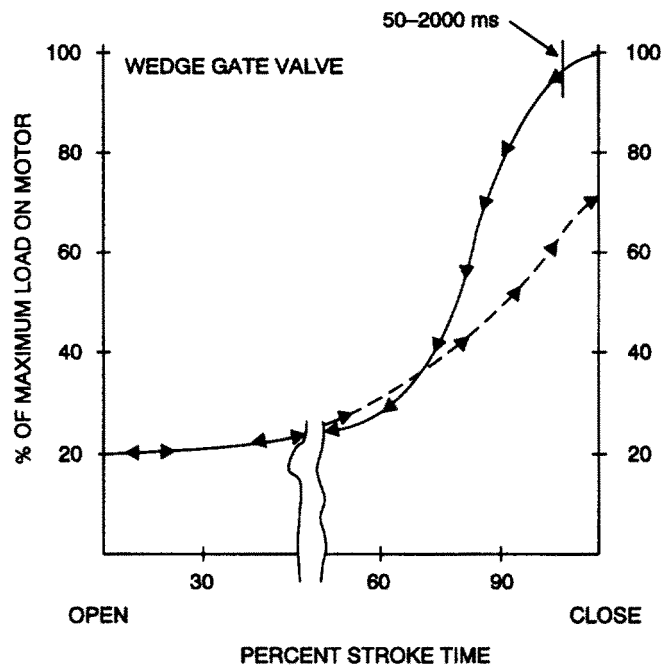


Figure 11.30 – Wedge Gate Valve Torque Requirements

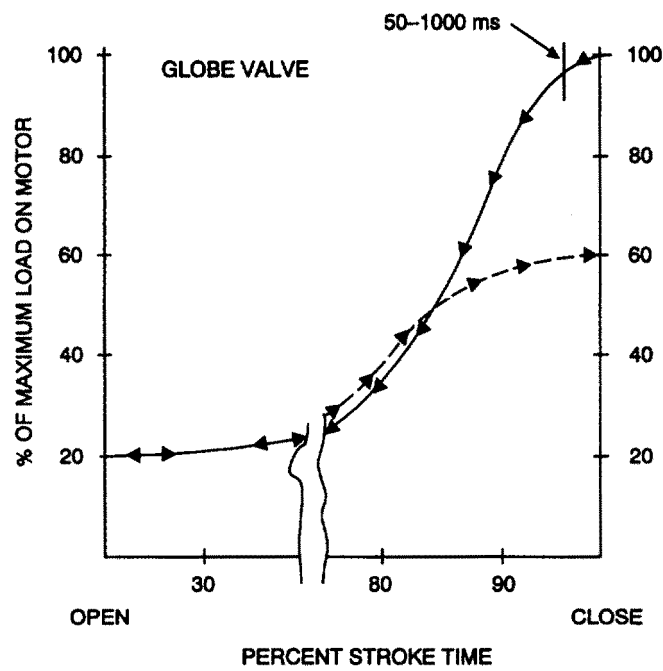


Figure 11.31 – Globe Valve Torque Requirements

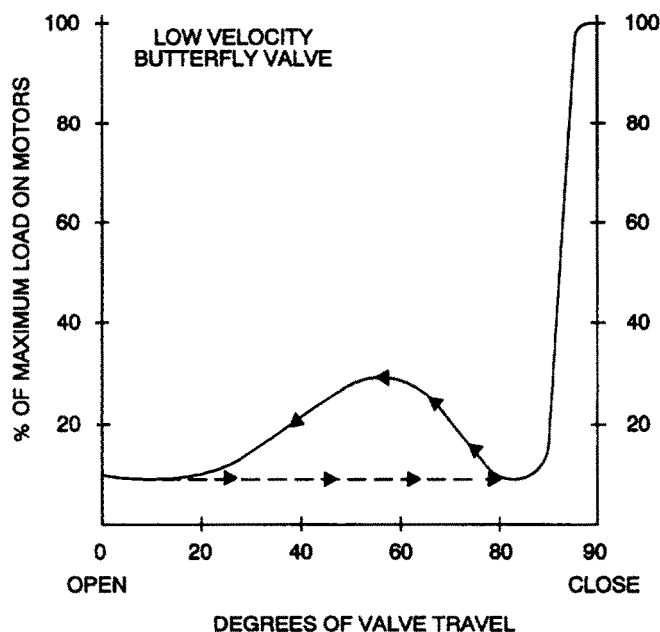


Figure 11.32 — Low Velocity Butterfly Valve

For the butterfly valves used in high fluid velocity applications (Fig 11.33), the dynamic torque could be as high or even higher than the seating or unseating torque. The peak dynamic torque lasts for only a small fraction of the total stroke.

11.6.6.2 Abnormal Operating Conditions of Valves

The valve motor actuators are equipped with position limit switches to stop the actuator at each end of travel. As a back-up to the position limit switches, a torque limiting switch is provided for each direction. If these switches are improperly set, the actuator will reach the end of travel in one direction or the other and will be mechanically limited from overtraveling. This will allow the motor to go into a stall or locked rotor condition. Motor overload protection must protect the motor for this condition.

In mid-travel, high running loads that are substantially greater than the normal running loads can exist due to either a nonlubricated or dirty stem or some type of binding in either the valve disc/wedge or stem. These high running loads would not be high enough to trip the torque switch because the seating/unseating loads or valve peak load (for which the switch is set) is usually three times higher than running loads. This means that the running load on the motor could be as high as 300% of expected load before the torque switch would stop the actuator. The only motor protection in this situation is the motor overload device.

It should be pointed out that the typical short operation times for motor operated valves would limit the vulnerability to a motor burnout due to a higher than normal running load.

11.6.6.3 Motor Performance and Design

In the previous section, the typical valve torque requirements were defined. The data indicated that the predominant requirement for a motor in valve actuator service is starting/stall torque. One manufacturer considers stall as locked rotor when approached from full load. Industrially, the proper definition would be starting torque. The motor, therefore, must have sufficient starting torque to overcome all of the seating/unseating or peak torque conditions previously identified.

Recognizing that motor frame size must be kept to a minimum to reduce inertia, it is also important to evaluate the running load requirements along with a suitable duty rating to tailor the motor to the application as closely as possible. It is also desired to match the running load requirements of the valve to the normal running load of the motor. This is desirable because when the normal running torque of the motor is equal to the valve required stroking torque, operating problems such as stem binding, etc., can be discovered quickly. Oversizing the normal running torque capability of the motor will mask a developing problem that could lead to more serious consequences later. From the previous torque curves for valve requirements, it can be seen that a running (normal) torque capability of 20% of rated starting torque would be a proper selection.

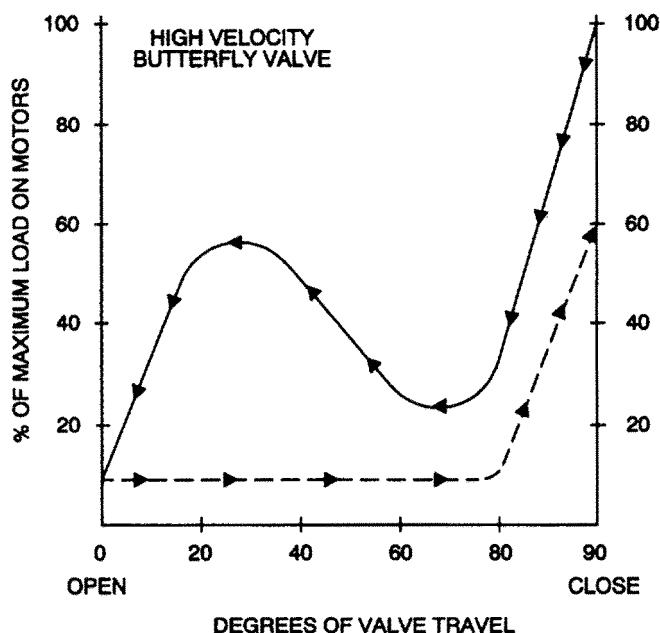


Figure 11.33 — High Velocity Butterfly Valve

Evaluating frame sizes for their inertial impact, a duty rating of 15 min is selected. This time rating accommodates almost all standard valve applications. Duty ratings below 15 min (for three phase) do not produce significant frame/inertia reductions and would serve a much smaller percentage of the number of applications.

11.7 DC Motor Applications

11.7.1 Power Plant Applications

In a power plant, the dc motors perform control functions such as turbine governor motor, governor limit setting, motor operated rheostats, and emergency lubrication for the turbines (main, boiler feed pumps) and the generator (H_2 oil seal). A fourth type of service is motor operated valves. The first and the fourth are intermittent type operations. The emergency type services are of short duration. The emergency lube oil pump running time depends on the turbine-generator runout time with vacuum or broken vacuum. For a large unit (600 MW), this may be 60 min and 30 min, respectively. The H_2 seal oil pump may be operated for 3–4 h. The turbine-generator emergency bearing oil pumps provide lubrication, the emergency seal oil pumps maintain H_2 seal in case ac power is unavailable. The dc motor operated valves usually perform essential services, i.e., one ac and one dc operated valve in parallel or in series with each other will assure opening or closing, respectively.

11.7.2 Control of DC Motors

11.7.2.1 Motors Performing Control Functions

This category consists of the turbine governor, governor limiting setting, motor operated rheostats, etc. These motors are small, about 1/8 hp or less. They are operated quite infrequently for short duration. The motor power circuit also contains the control elements. This is usually a three position, lower-off-raise control switch, rated 600 V and contacts rated for 20 A. The branch circuit protection is provided by two pole molded case circuit breakers or fuses. The end position of the travel of the device and its movement is displayed by indicating lights in the same circuit as the motor.

11.7.2.2 Motors Performing Emergency Services

This category consists of turbine-generator emergency (lubrication) bearing oil pumps and emergency seal oil pumps. Such pumps may also be provided for steam turbine drives of feedwater pumps, fans, and other large loads. The lack of lubrication during a shutdown without ac power will ruin the linings of the bearings and damage the shaft.

The branch circuit protective devices for these drives could be a two pole power circuit or molded circuit breaker or fuses (if their output is monitored). This device should provide short circuit protection only (i.e., it should have magnetic trip set, as a minimum, three times the initial starting current of the first stage of the starter).

The starters are the reduced voltage nonreversing type. Resistance is inserted in the armature circuit to reduce the armature current until the counter emf develops to limit the current as the armature accelerates. In effect, insertion of resistance reduces the voltage across the armature. The resistance is removed in steps as the motor accelerates. The cutout of resistors in the starting sequence is governed by timers. Hence, the cutout could occur at a time when the counter emf of the motor did not develop to a magnitude that would prevent a switching current exceeding the initial starting current. This phenomenon is the basis for the setting of the branch circuit protective device.

The thermal overload device in the starter should not cause tripping, but it should initiate an alarm. Motor damage is justified when trying to avoid damage resulting in more serious consequences.

11.8 Starting Large AC Motors

11.8.1 Full Voltage Starting

Full voltage starting of ac motors is desirable to obtain simplicity and economy in the starting equipment. Modern ac motors are designed to withstand the application of full voltage at standstill without damage to the motor windings. Unfortunately, larger motors have full voltage starting currents that may be objectionable on weak power systems. The starting currents flowing through the system reactance cause voltage dips that result in reductions to the motor developed torque. The available torque during starting should be determined to ensure successful acceleration without excessive motor thermal duty.

Section 12 of ANSI C50.41-1982 [1] contains information regarding the starting capabilities of large ac motors. Section 13 of ANSI C50.41-1982 [1] contains information regarding the allowable rotating moment of inertia of connected mechanical loads. Section 14.2 of ANSI C50.41-1982 [1] addresses minimum voltage and permissible load characteristics during starting. A method for determining if a motor and load will accelerate successfully and for calculating accelerating time is presented in 11.17.2 of this guide.

In addition to the items of information listed in the standard, the required number of starts in succession should be specified if it differs from the standard. Refer to 11.8.4 of this guide and ANSI C50.41-1982 [1], Sections 12.1.1 and 12.1.2.

11.8.2 Reduced Voltage Starting

The four usual methods of reduced voltage starting used to reduce the current drawn by the motor are

- 1) The autotransformer method
- 2) The series resistor method
- 3) The series reactor method
- 4) The unit or dedicated-transformer method

These methods often require no modification of the motor for their use. Reduced voltage starting is rare in generating stations.

11.8.3 Motor Modifications for Starting

Three other methods of reducing the starting current drawn by a motor are used. Occasionally, these methods require modification of the motor windings. Thus, in order to be used, the intended method must be specified at the time the motor is ordered. The wye-delta method requires extra motor leads and a motor winding designed for delta connection for normal operation. The series-parallel method requires the proper number of sections in each phase of the motor winding as well as adequate leads. The part-winding method requires two parallel windings per phase, the proper number of leads, and, in addition, other design problems must be considered.

In any instance in which one of these last three methods is being considered, the availability of a motor for this type starting must be checked with the manufacturer.

All of the above methods, either reduced voltage or special winding arrangement, result in a considerable reduction in available torque during the starting cycle. Therefore, torque requirements at start should be carefully considered.

11.8.4 Frequency of Starts

Standard squirrel cage induction motors are suitable for two successive starts with the motor initially at ambient temperature (coasting to rest between starts), or one start from rated temperature. Subsequent starts should not be attempted until the motor has returned to normal operating temperature. (Refer to Section 20.43 of NEMA MG1-1987 [7] and Section 12 of ANSI C50.41-1982 [1].) The factors effecting the number of starts that a given motor can survive in a given period of time, or in its lifetime, are so many and so varied that it is not practical to tabulate the number of motor starts in a general table. Among the factors are the load inertia, the load speed-torque characteristics, the frequency of starts, the method of operation, the ambient temperature, the enclosure to be required, the maintenance practices, and the class of insulation.

Each start made by a squirrel cage induction motor decreases the motor life. Starting duty imposes severe mechanical stress on the end-turns of the motor stators and, in cases where high inertia loads are involved, can produce temperature excursions that can damage the stator insulation or the squirrel cage rotor, unless the motor has been specially designed for such service. Following a start, a motor will normally cool to normal operating temperature more quickly when running at full load than when it is stopped immediately following the start. A motor will cool more quickly when running at light load than when running at full load. The time required to cool to normal operating temperature will vary from motor to motor depending on such things as load inertia, load torque, voltage during the start, initial temperature conditions, motor enclosure, and ventilation. Individual consideration must be given to each motor for any starting capability beyond that specified in NEMA MG1. The motor manufacturer must be consulted regarding any additional capability.

These comments apply to either synchronous or induction motors. With synchronous motors, it is possible to make design changes that will improve the number-of-starts capability. Induction motors, using standard construction, have a number-of-starts capability that is about the maximum practical. A further increase of the number-of-starts capability of induction motors would most likely require a compromise on other motor characteristics, which generally proves unsatisfactory.

On applications with very high inertias (five to ten times NEMA normal) and/or requiring repeated starts and stops, wound rotor motors or adjustable-speed drives should be considered. By introducing resistors or reactors, currents and torques can be controlled during the accelerating and decelerating cycle. The reduced current results in less mechanical stress and significantly lower temperature excursions than those experienced by squirrel cage induction or synchronous motors during starting. Most of the rotor-circuit heating occurs in the external resistances.

11.9 Effects of System Operating Conditions on Motor Characteristics

11.9.1 Voltage and Frequency Variation

11.9.1.1 Capability for Continuous Operation at Rated Horsepower

Section 14.1 of ANSI C50.41-1982 [1] specifies allowable voltage and frequency ranges for continuous operation.

Fig 11.34 is a graphical representation of the continuous operating capability at other than rated voltage and frequency. Continuous torque capability as a function of frequency at rated voltage is also shown in Fig 11.34 (this represents a constant horsepower load).

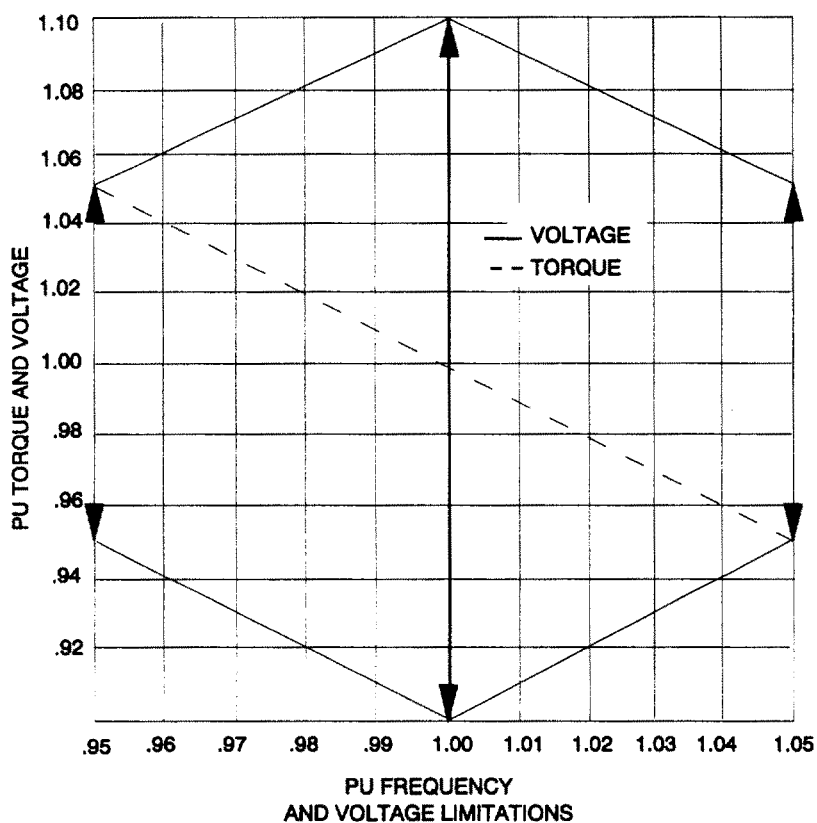


Figure 11.34 — Torque Capability as a Function of Frequency at Rated Voltage

Approximate effects of voltage and frequency variation are presented in Table 11.5 for integral horsepower (medium) motors and in Table 11.6 for large motors.

11.9.1.2 Unbalanced Auxiliary Power System Voltages

Unbalances can be of extended duration when only two out of three poles of a disconnect switch or of a circuit breaker close, or when one of the phase conductors breaks.

Another type of extended duration unbalance can be caused by single phase loads. These loads can be found in the low-voltage portion of the auxiliary system, i.e., on the secondary side of the unit substation transformer. Their effect is more severe on the secondary than on the primary side. These transformers are usually 500–2500 kVA. The single phase loads may be a maximum of 150 kVA. Typically, these loads are precipitators and large single phase uninterruptible power supplies.

Transient type unbalances are caused by phase-to-phase faults, phase-to-phase-to-ground faults, and single-phase-to-ground faults.

Section 20.56 of NEMA MG1-1987 [7] addresses the effects of voltage unbalance on polyphase motors and provides recommendations for motor derating as a function of voltage unbalance.

The percent voltage unbalance is defined by NEMA MG1-1987 [7] as

$$\text{percent voltage unbalance} = 100 \cdot \frac{\text{maximum voltage deviation from average voltage}}{\text{average voltage}}$$

Table 11.5 — Approximate Effect of Voltage and Frequency Variation on Integral HP Motors

Characteristics	Voltage		Frequency	
	110%	90%	105%	95%
Torque, starting and breakdown	Increase 21%	Decrease 19%	Decrease 10%	Decrease 11%
Speed:				
Synchronous	No change	No change	Increase 5%	Decrease 5%
Full load	Increase 1%	Decrease 1.5%	Increase 5%	Decrease 5%
Full load efficiency	Increase 4–6 points	Decrease 2 points	Slight Increase	Slight decrease
Full load power factor	Decrease 4 points	Increase 1 points	Slight Increase	Slight decrease
Currents:				
Starting	Increase 10–12%	Decrease 10–12%	Decrease 5–6%	Increase 5–6%
Full load	Decrease 6%	Increase 10%	Slight decrease	Slight increase

Table 11.6 — Approximate Effect of Voltage and Frequency Variation on Large Motors²³

Characteristics	Voltage		Frequency	
	110%	90%	105%	95%
Torque*				
Starting and maximum running	Approximate increase 21%	Approximate decrease 19%	Decrease 10%	Increase 11%
Speed [†]				
Synchronous	No Change	No Change	Increase 5%	Decrease 5%
Full load	Increase 0.1–1.25%	Decrease 0.13–1.5%	Increase 5%	Decrease 5%
Percent Slip	Decrease 16–24%	Increase 20–30%	Little Change	Little Change
Efficiency				
Full load	Decrease of 2.0 to increase of 0.5 points	No change to decrease of 1.5 points	Slight increase	Slight decrease
3/4 load	Decrease of 0.1–4.0 points	Decrease of 0.2 to increase 1.0 points	Slight increase	Slight decrease
1/2 load	Decrease of 0.5–4.0 points	Increase 0.1–3.00 points	Slight increase	Slight decrease
Power factor				
Full load	Decrease of 2–8 points	Increase of 0.5–5 points	Slight increase	Slight decrease
3/4 load	Decrease of 6–10 points	Increase of 2–7 points	Slight increase	Slight decrease
1/2 load	Decrease of 9–12 points	Increase of 4–10 points	Slight increase	Slight decrease
Current				
Starting	Increase of 10–12 points	Decrease 10–12 points	Decrease 5–6 %	Increase 5–6 %
Full load	Increase of 4% to decrease of 7%	Increase of 5–11%	Slight decrease	Slight increase
Temperature	Increase of 5% to decrease of 8%	Increase of 5–20%	Slight decrease	Slight increase
Maximum overload capacity	Increase of 21%	Decrease 19%	Slight decrease	Slight increase
Magnetic noise	Slight increase	Slight decrease	Slight decrease	Slight increase

Courtesy of General Electric Company

*The starting and maximum running torque of ac induction motors will vary approximately as the square of the voltage.

†The speed of ac induction motors will vary directly with the frequency.

Example: With voltages of 460 V, 467 V, and 450 V, the average is 459 V, the maximum deviation from the average is 9, and the percent unbalance = $100 \cdot 9/459 = 1.96\%$.

Unbalanced system voltages have a positive sequence and a negative sequence component voltage (ground faults also have a zero sequence component). Consequently, there are corresponding magnetic fluxes. While the positive sequence flux (for the external observer) rotates in the direction of the rotor rotation, the negative sequence flux rotates in the opposite direction, thus its relative speed or frequency versus the rotor is double the normal power frequency. The interaction of negative sequence voltage with its currents produces a torque acting in the reverse direction, as compared to the positive sequence torques.

²³Values shown are typical for polyphase squirrel-cage motors of normal characteristics, actual values and range will vary with individual rating and design.

The resultant torque is the sum of the two. For the extreme case of an open phase, the resultant torque vs. speed (slip) curves are shown in Fig 11.35. The following can be observed from Fig 11.35:

- 1) A three phase induction motor cannot start from standstill when one of its phases is lost because the resultant torque is 0 at standstill.
- 2) When a running motor experiences a loss of one of its phases, it will continue to operate at a lower full load speed, $N_{1\Phi}$, instead of the rated speed, N , because the required resultant torque for that load is available at the speed of $N_{1\Phi}$. It is also to be noted that the phase current for loss of one phase operation is approximately two times the normal full load current. The increased current and core losses can overheat the motor. Therefore, protection should sense such a condition and disconnect the motor before damage can occur. The latter can be explained as follows: Motor input kVA = $\sqrt{3} V_{\Phi\Phi} I_{\Phi}$ for normal three phase operation. If the motor continues to operate at full load, its input kVA would remain essentially the same for the same power factor and efficiency. Since only one phase-to-phase voltage is present, the equation is satisfied when the current is increased to $\sqrt{3} I_{\Phi}$. Changes in power factor and efficiency result in an actual value of approximately $2I_{\Phi}$. The current increments for varying degrees of voltage unbalance are six to eight times the value of the unbalance.

The case discussed above is the extreme one. For varying degrees of unbalance, the limitations are less severe.

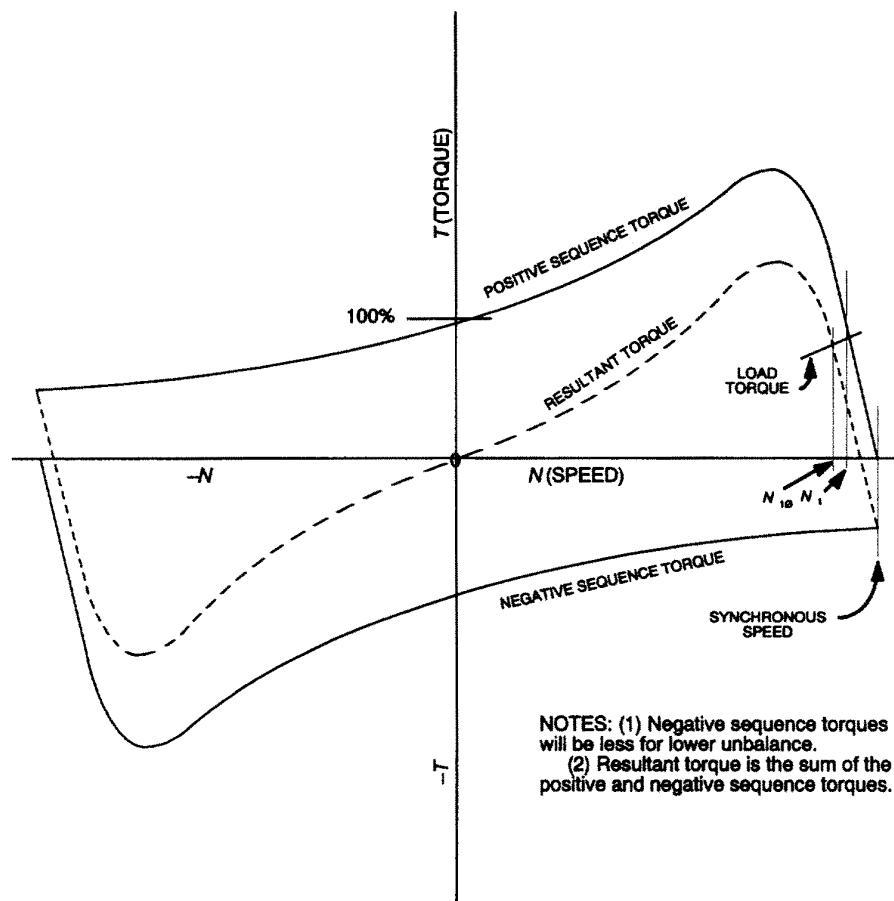


Figure 11.35 — Positive, Negative, and Resultant Torques for Loss of a Phase Voltage

11.9.1.3 Capability of Large Induction Motors for Short Time Operation

11.9.1.3.1 Momentary Operation at Reduced Voltage

ANSI C50.41-1982 [1] requires that motors be capable of running at rated load for 60 s with a minimum terminal voltage of 75% of rated voltage at rated frequency.

11.9.1.3.2 Short Time Overload and Reduced Load Capability

For voltages and frequencies below the allowable ranges specified for continuous operation in Section 14.1 of ANSI C50.41-1982 [1], the load for continuous operation can be estimated from Figs 11.36, 11.37, and 11.38. These figures have the following conditions and limitations:

- 1) The upper voltage limits represent the values in the standards for the .95–1.0 pu frequency range.
- 2) The upper voltage limit at .9 pu frequency is determined at 1.1 pu V/Hz.
- 3) The lower voltage limit at 1.0 pu frequency is the value in the standards.
- 4) The lower voltage limit at .95 pu frequency is based upon current corresponding to 1.05 pu torque, .95 pu frequency, and .95 pu voltage. This current is approximately 1.05 pu.
- 5) The lower voltage limit at .9 pu frequency is based on limiting the current to approximately 1.05 pu.

Figs 11.36, 11.37, and 11.38 represent capability for three different load torque characteristics. Fig 11.36 represents constant torque vs. frequency, Fig 11.37 represents load torque varying directly with frequency, and Fig 11.38 represents load torque varying as the square of the frequency. Speed is essentially proportional to frequency.

If the operating condition falls within the cross-hatched area, for the particular type of load involved, then it is reasonable to assume that the motor can operate under this condition continuously without harm to the motor.

When the available voltage at a particular frequency is lower than the limit shown in Figs 11.36, 11.37, or 11.38, and it is desired to estimate how long a motor may operate under this condition, it is necessary to determine the corresponding current. Once the current is determined, the thermal limit curves for the particular motors involved, similar to Fig 11.39, may then be used to determine how long the motor may operate without injurious heating.

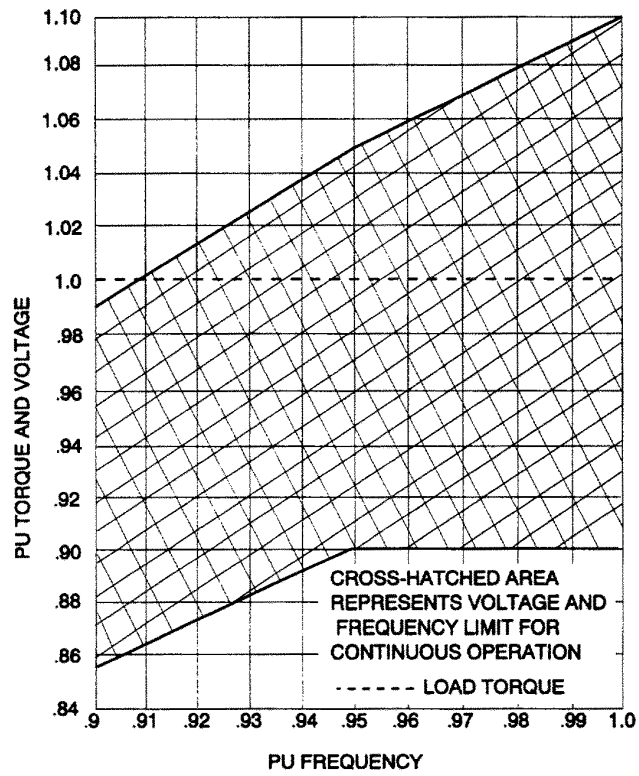


Figure 11.36 — Voltage Limits for Continuous Operation vs. Frequency (Load Torque is Constant With Frequency)

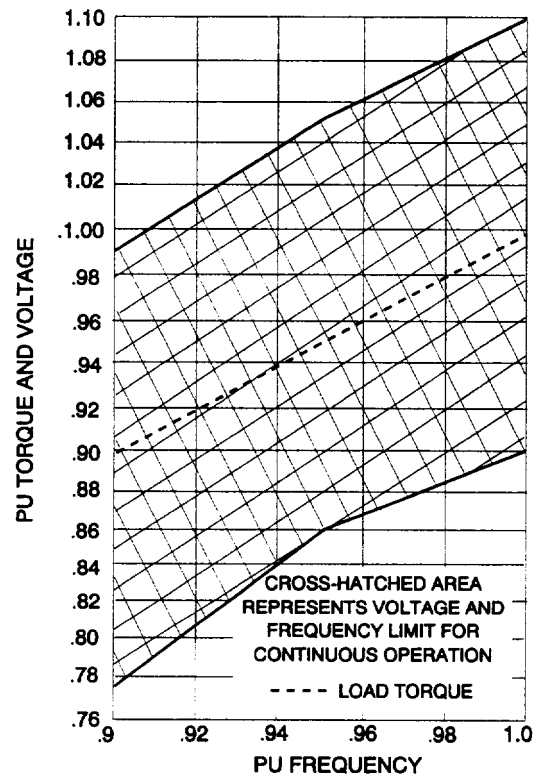
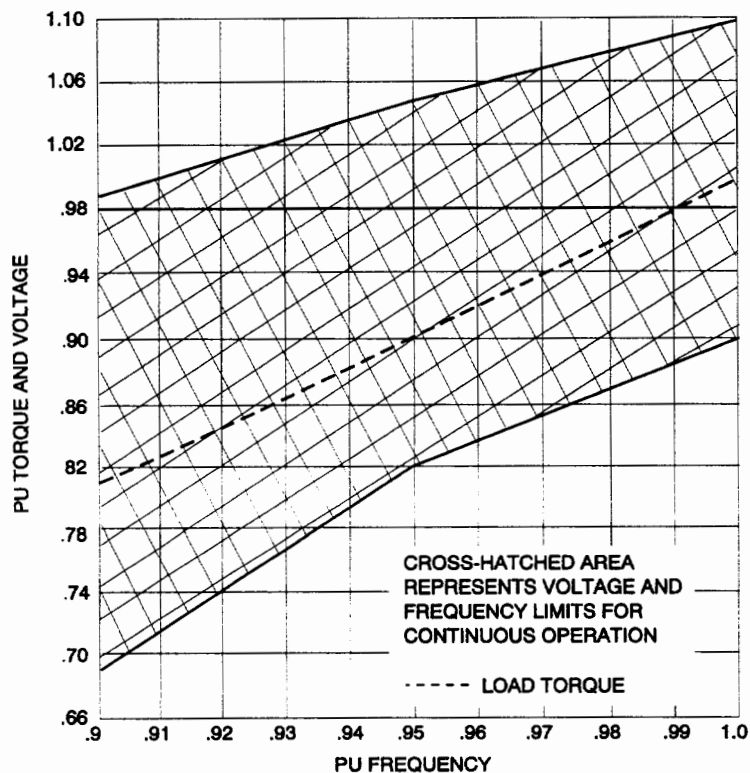


Figure 11.37 — Voltage Limits for Continuous Operation vs. Frequency
(Load Torque Varies Directly With Frequency)



**Figure 11.38 — Voltage Limits for Continuous Operation vs. Frequency
(Load Torque Varies as the Frequency Squared)**

Fig 11.39 is a representative thermal limit curve. The top portions of the curves apply for 1.15 and 1.0 service factor motors. The lower portion of the curve can be considered to apply for either rating of motor. The break in the curve occurs at a value of current representing approximately the maximum torque point of the motor. The top portion represents the thermal limit with the motor running. The bottom portion represents the thermal limit with the motor at standstill or starting. Ordinarily, the top and bottom portions are blended into one when such a curve is supplied. The descriptive comments on the diagram give limits of V/Hz, limits on frequency, and limits on voltage under which this curve applies.

The limits defined for V/Hz, frequency, and voltage have been chosen at values that are judged to meet most of the practical operating conditions.

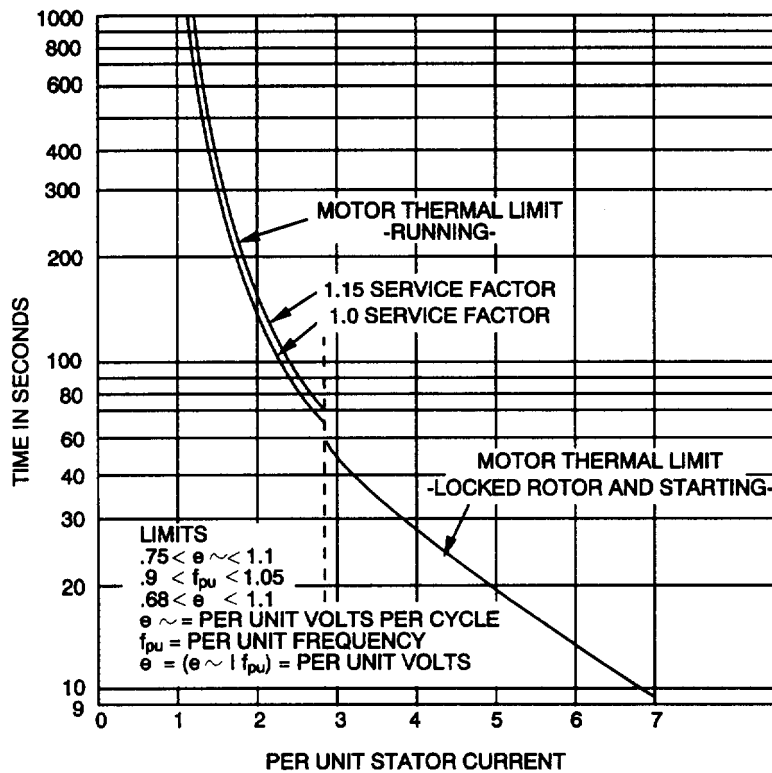


Figure 11.39 — Typical Time Limit Curve (Generally Applicable With the Frequency and Voltage Ranges Indicated)

The motor current can be estimated by

$$I \text{ (pu)} = \frac{\text{Torque (pu)}}{\left(\frac{\text{Voltage (pu)}}{\text{Frequency (pu)}} \right)} \cdot C$$

where

C is determined from Fig 11.40.

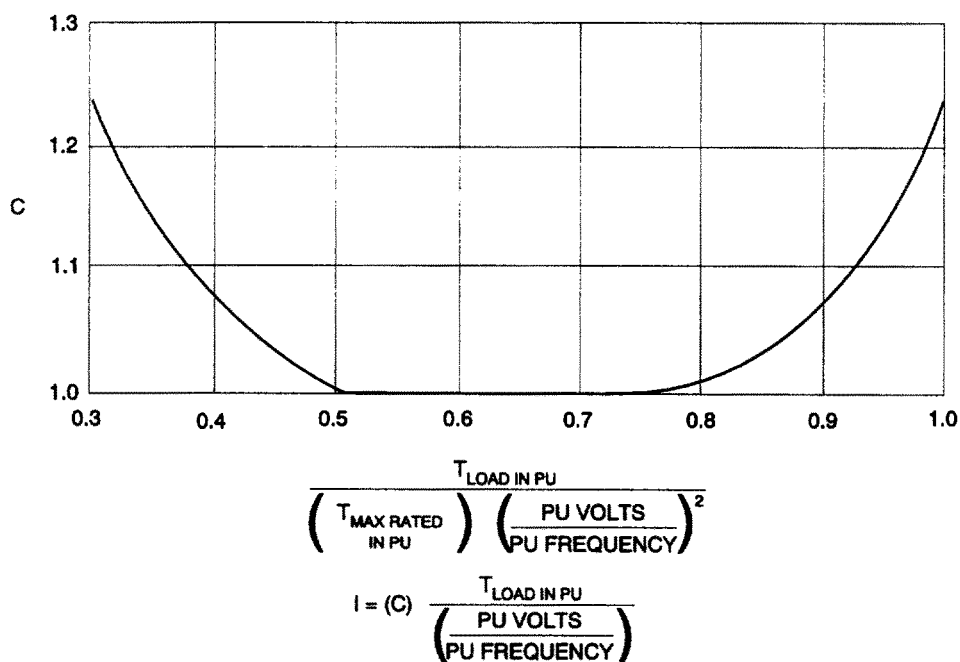


Figure 11.40 — Chart for Determining C

It will be noted that $C = 1.0$ within the normal loading range of motors. However, at light loads and also at maximum loads approaching breakdown torque, C increases rapidly.

11.10 Effects of Motor Operation on the Power System

11.10.1 Motor Starting Voltage Dip

Starting currents of ac motors are very high with respect to normal full load currents. Typical large squirrel cage induction motors, for example, have starting currents between 600–650% of their full load currents. Depending upon the application requirements, the starting currents of motors for generating station applications can range between 450–750% of rated currents. Standard, unity power factor synchronous motors often have starting currents approximately 400% of rated current. Most large synchronous motors applied in generating stations drive circulating water pumps whose torque requirements often result in starting currents of 600%. The high starting current condition exists with very slight reduction until the drive being started accelerates to nearly full speed. High starting currents of a system's largest motors produce significant voltage dips in the station electrical system for the durations of the motor starts. The induction motors driving the large boiler fans (or the boiler feed pumps in the case of smaller generating units) usually produce the most severe motor starting voltage dips.

These voltage dips have varying degrees of impact on the system depending on the duration and magnitude of the dip. Some system components are more sensitive than others to voltage dips. Lighting levels are affected, and, for severe dips, controls and computers might not function properly. During severe dips, ac motor starters that do not have latched-in contactors may drop out. The voltage dip always has some impact on the starting motor and motors that are running, although the impact might be inconsequential. Acceleration of the starting drive depends upon the net accelerating torque (the difference between motor developed torque and load torque) and the inertia of the motor rotor and load. Motor developed torque varies, approximately, in proportion to the applied voltage squared. At reduced voltage, the reduced accelerating torque increases starting time and, therefore, the time the motor is subjected to the high heating rate caused by the starting currents. Excessively low voltage during starting may reduce the motor torque

to a value that results in zero net accelerating torque at a speed below full-speed, preventing the drive from operating successfully and requiring tripping of the motor circuit. Low voltage also affects drives that are running when the voltage dip occurs. The maximum (breakdown) torque capability of induction motors and the pull-out torque capability of synchronous motors decrease with reduction in applied voltage. If the voltage at the terminals of running motors dips excessively, the motors might not develop sufficient torque to prevent drives from decelerating toward stall conditions. As the drives decelerate, motor currents increase to starting values, further reducing the voltage.

The value to which the voltage is permitted to dip during a motor start is one of the major design criteria for the service system. The establishment of this criterion and the trade-offs between motor starting current and system performance are discussed elsewhere in other sections.

11.10.2 Motor Short-Circuit Contributions

Section 6. contains details concerning short-circuit current calculations for the purpose of selecting circuit breaker ratings. Electric motors act as generators during system short circuits, contributing current to the faults. Depending upon the specific location of the fault, the current contributions from motors may need to be included in the total fault current for circuit breaker selection. When a short circuit occurs, there is normally a voltage reduction at the point of fault, the magnitude of which depends upon the amount of impedance in the fault. The voltage is also reduced to a lesser degree in other portions of the system with the reduction generally being less toward the system sources. The voltage profile of the system is generally governed by the impedance between components through which the fault currents flow. If the terminal voltages of motors are reduced during a fault, the trapped fluxes in the machines appear as the excitation fluxes of a generator. Initially the voltages induced in the motor windings due to the trapped fluxes are higher than the terminal voltage, and the motors produce fault current limited by the motor reactance and the system impedance between the motor and the fault. The magnitude of current, as a function of time, depends upon the total impedance to the fault and the motor short-circuit time constant.

IEEE C37.010-1979 [4], paragraph 5.4.1, contains reactance multipliers that are recommended for motor representation in system equivalent circuits for short-circuit current calculations.

These multipliers (based on typical time constants) are used to estimate the initial value of fault current (“momentary” or “close and latch”) and the value at the time of fault interruption.

These multipliers are typical, based on many machines, and are intended to be conservative. The table is arranged to provide data for ranges of ratings of induction motors and synchronous motors. For many large induction motors, the table provides quite conservative data. Where large machines could have a significant effect on circuit breaker selection, it is recommended that short-circuit time constants for the specific machines be used, if obtainable.

11.10.3 Bus Transfer or Fast Reapplication of Power (Reclosing) for Large AC Motors

11.10.3.1 Motor Characteristics

A rotating induction motor that is open-circuited under load has a certain amount of electromagnetic energy stored in its magnetic structure and mechanical energy stored in the rotating parts of the motor and load. The result is that, upon separation from the system, a residual voltage will occur at the stator terminals, the magnitude and frequency of which decay with time. The initial values are slightly less than the system voltage and frequency.

The motor speed and, therefore, the frequency of the residual voltage decay at a rate determined by the load characteristics and the inertia of the motor and load. Since the initial frequency is less than the line frequency, and the frequency changes with time, the phase angle of the residual voltage also changes relative to the system voltage. The magnitude of the residual voltage decays exponentially according to the motor’s appropriate time constant. The effective time constant will be reduced by the change in speed, depending upon the rate of change. Any short circuits on the system will increase the rate of voltage decay.

The behavior of a number of motors simultaneously disconnected from their power source while maintaining their electrical interconnection may be affected by the electrical coupling, the extent of which depends upon the magnitude of energy transfer between motors.

If all motors are identical electrically and mechanically, they will all decelerate at identical rates, and no interchange of stored mechanical and electric energy will take place. This condition is just as if each motor were individually open-circuited.

If the motors are not identical, the situation is different. A motor with an inertia greater than the average will decelerate more slowly and, as long as its rotor flux remains appreciable, will supply energy to the other motors that have inertias smaller than the average. As compared with the open-circuited condition, the high inertia motors will decelerate more rapidly, while the low inertia motors will not decelerate as rapidly. The result is a tendency to stay “synchronized.” Due to the energy transfer between machines, residual voltage of all motors and the motor bus will decay at very nearly the same rate.

A synchronous motor contained in a group of induction motors may exert a decided influence on the overall behavior of the group if the field has not been removed. In effect, it will tend to behave like a synchronous generator or an induction motor with a very large open-circuit time constant and, thus, will tend to hold the residual bus voltage at a higher value than if the synchronous motor were not present. However, if the field has been removed by the relaying due to the disturbance, the motor will act similarly to an induction motor, except that it might tend to have a shorter open-circuit time constant than an induction motor of comparable size. This is a function of the magnitude of the discharge resistance in the field and the amortisseur winding resistance.

Wound rotor induction motors are not designed to withstand full-voltage inrush currents with the slip rings short-circuited or nearly short-circuited. Therefore, the effects of any automatic transfer scheme on such motors should be considered in detail for any such application.

The presence of any shunt capacitance on the bus to be transferred will tend to retard the decay of the residual voltage. When analyzing such a system, the existence of any capacitance should be accounted for in mechanical torque.

11.10.3.2 Methods of Bus Transfer

One method of reapplying power is to close the reserve feeder source breaker after a deliberate time delay. The practice has been to allow the residual bus voltage to decay to about 25–30%; before the transfer is completed. The residual voltage is allowed to drop to this low value to eliminate any excessive disturbance to the motors when the bus is reenergized.

Two important considerations in specifying the allowable residual bus voltage magnitude at the time of transfer are the transient torques produced in the motor and driven load equipment and the winding stresses produced in the motor by inrush currents. The subject of transient motor torques and winding stresses is a complex one because of the number of variables involved.

Experience has indicated that if the residual voltage at the time of transfer is 30% of rated voltage or less, the inrush current will be low enough to avoid excessive stresses on the windings. This means that if the residual bus voltage is 180° out-of-phase with the reserve source voltage at the time of transfer, the inrush current will be about 130% or less of full-voltage starting current.

From the standpoint of transient electrical torque, transferring at the worst angle and with residual voltage of between 90–100%; produces a peak electrical torque as high as 10–20 times rated torque. If the residual voltage is 30% or less, the peak electrical torque typically would not exceed three times the rated torque.

As motor ratings have increased, this method of bus transfer has become more of a problem. Larger motors, with their larger time constants, have made it necessary to wait a long time for the residual voltage to decay to the transfer value.

Waiting a longer time raises problems of more severe voltage dips, longer recovery times, and possible stalling of some of the motors.

With the development of very fast-acting circuit breakers, a second method of bus transfer is practical in some cases. In this method, the interruption-reclosing takes place so rapidly that the change in phase relationship between the motor residual voltage and the power system has not changed sufficiently to be potentially dangerous. Providing that the normal and reserve source voltages are in phase when the transfer is initiated, the maximum time that both sources can be disconnected from the bus is approximately 6 c for typical induction motors and 5 c for typical synchronous motors. For special machines, very low inertia drives, or where the sources voltages are not in phase, careful analysis of the system dynamics during the transfer must be made to determine if fast bus transfers under particular operating conditions can be tolerated without potential damage to the machines.

A recommended criterion for preventing damage to motors is published in Section 15 of ANSI C50.41-1982 [1].

Regardless of which system is used, the motor and load characteristics must allow reacceleration of all essential motors after reapplication of voltage. After the reapplication of voltage, there is a period of adjustment as motor fluxes approach their steady state values. During this period, the motors will accelerate or continue to decelerate, depending upon the bus voltage and the individual motor and load characteristics. Depending upon the stiffness of the electrical system and the higher motor currents, the bus voltages may be appreciably less than that required to develop electrical torques that will result in reacceleration of all drives. This situation may improve with time if some motors accelerate successfully, and their currents decrease to steady state values resulting in some recovery of bus voltage. Bus transfer methods are discussed in additional detail in Section 4.

11.11 Motor Protection Requirements

Properly applied motor protection equipment can provide several benefits. Among these benefits are

- 1) The protection of motors from hazards that are inflicted on, or initiated in, the power system to which the motors are connected
- 2) The detection of possible hazards that are the result of operating problems in the motor, the driven equipment, or the surrounding environment
- 3) The detection of faults within the motor windings or problems in the bearings

The following paragraphs provide a general discussion of some of the types of motor protection that are applied in generating stations. More detailed discussions of the application and coordination of protective relays on motor circuits are presented in Section 7..

11.11.1 Protection of Motor Windings

11.11.1.1 Overload Protection

IEEE Std 100-1988²⁴ defines *overload* as the output of current, power, or torque, by a device, in excess of the rated output of the device on a specified rating basis. Overload of electric motors results in an operating overcurrent that, when it persists for a sufficient length of time, can cause damage or dangerous overheating of the motor. It does not include short circuits or ground faults. Overload is usually detected by phase overcurrent relays or thermal overload relays.

Most drive motors in generating stations are applied in a fairly conservative manner so that operating conditions rarely cause motor overload. Motor overloads usually indicate mechanical problems in the motor (possibly bearings) or the driven equipment. An overcurrent condition will not always result in dangerous overheating of the motor windings,

²⁴See footnote 20.

particularly if the ambient temperature is low. The reason for higher than normal current should be investigated and corrective action should be taken. Refer to 11.11.1.2.

11.11.1.2 Overtemperature Protection

Overtemperature conditions in motor windings due to moderate overloads should be detected and investigated to prevent damage to insulation and/or conductors. Excessive temperature rise that occurs in a short time, such as the situation in which a motor fails to start and accelerate in the expected length of time, must be prevented by tripping the motor circuit as the result of relay action. Investigation of these conditions should be completed prior to reenergizing the motor.

Conditions other than persistent overcurrents can cause a motor to overheat, such as successive failures to start, high ambient temperature, poor motor ventilation, improper installation (e.g., too close to wall, too close to other motor air outlet ducts), and unbalanced phase voltages. Monitoring overcurrent alone with remote devices (current transformers and relays in switchgear) will not detect overheating due to these causes.

For large motors, the principal means of protecting the stator windings against long term overtemperature is the resistance temperature detector (RTD). The detectors are embedded between coils in the stator slots during manufacture. Thermocouples can also be applied in this manner. RTDs can be connected to temperature monitoring devices or to a relay for alarming or tripping. Monitoring equipment can consist of a selector switch, connected to the six stator winding RTDs and bearing RTDs (if any), and a switchboard type temperature instrument. The RTDs should be monitored regularly so that any changes not explainable by load conditions and/or ambient temperature can be recognized and investigated. The output of temperature detectors can be input to a computer for continuous on-line monitoring. The stator RTD that usually indicates the highest temperature is the one that should be connected to the relay. Where RTDs are not used (usually on smaller medium voltage motors), thermal overload relays can be applied in place of time overcurrent relays. The thermal overload relay, which senses motor current, has some memory due to its bimetallic element, but it is more difficult to apply than time overcurrent relays.

RTDs are preferred over the thermal overload relay because they sense motor temperature directly. The thermal overload relay has a broad operating band relative to the overcurrent relays and may be difficult to coordinate with the motor thermal limit and motor accelerating curves if the accelerating time approaches the motor thermal limit curve.

11.11.1.3 Short-Circuit Protection

Short-circuit protection for large motor feeders is provided usually by instantaneous overcurrent relaying. Three phase and phase-to-phase faults are sensed normally by instantaneous overcurrent elements that are packaged with the time overcurrent relays that provide overload protection. The instantaneous and time overcurrent elements share the same current transformer secondary.

Phase-to-ground faults are sensed normally by instantaneous overcurrent relays in combination with a toroidal current transformer through which all three phase conductors pass. Theoretically, only zero sequence current flows in the relay. Where the auxiliaries system is low-resistance grounded at the transformer neutral (maximum neutral current limited to 200–1200 A), a faulted feeder is tripped instantaneously. For highresistance grounded systems (2–5 A maximum ground fault current), annunciator action alerts plant operators to schedule a shutdown of the faulted feeder at the earliest possible time. It is imperative to remove the faulted feeder as soon as possible to limit damage in the faulted equipment.

Differential relaying is not universally applied to large auxiliary drive motors. Where it is used, it is generally applied only to the largest motors in the auxiliaries system.

11.11.1.4 Protection for Stall Conditions or Failure to Accelerate

Stall protection and protection against failure to accelerate to full speed within an appropriate time are normally provided by the phase-overcurrent relays used for overload protection. For some high inertia loads that must start at

low-voltage conditions, it is impossible to provide protection with a single overcurrent relay in each phase. These more difficult protection problems can usually be solved with one or more of the following schemes:

- 1) Multiple time overcurrent relays per phase
- 2) Timing relays and speed switches in conjunction with overcurrent relays
- 3) Impedance relays in conjunction with overcurrent relays or voltage relays

11.11.1.5 Undervoltage Protection

Protection from sustained system undervoltage conditions is normally provided by time-undervoltage relays that are located at the switchgear bus. Auxiliary drive motors supplied by a common bus normally do not have individual undervoltage detection. For system undervoltage conditions, the entire bus is normally tripped or transferred (refer to 11.10.3 for discussions of bus transfer).

11.11.1.6 Surge-Voltage Protection

Complete surge protection is provided with surge arresters and surge capacitors. Historically, the utility industry has applied surge protection to a small percentage of generating station auxiliary motors. Where surge protection is applied, it is usually applied only in the form of surge capacitors to slope off the steep wave fronts associated with switching surges initiating in the auxiliaries system. The capacitors protect the turn insulation. Surge arresters that limit the peak voltage of a surge protect the ground wall insulation. There is a general opinion in the utility industry that generating station motors are not exposed to surges caused by lightning and, therefore, surge arresters are rarely applied.

Where surge protection is applied for motor protection, the protective equipment should be properly installed directly at the motor terminals. This is particularly important for the surge capacitors to be effective. On motor feeders of less than 1000 ft cable length, switched by vacuum interrupters, surge arresters are often located at the load side of the interrupter to limit the magnitude of surge voltage.

11.11.1.7 Unbalanced Voltage Protection

Unbalanced phase voltages, which can cause overheating (particularly of the rotor), are rarely a problem in generating stations because the voltage balance is quite good. Since circuit breakers are used as motor starters for medium-voltage motors, open phases are not a common problem. Where fused motor starters are applied, it is important to provide some protection to ensure against single phase operation following a fuse interruption. This can be provided with a device that automatically trips the contactor following a fuse interruption. Where protection against unbalanced voltages is desired, it can be provided with phase-balance current relays for each motor feeder, or through the monitoring of the bus with a phase-sequence voltage relay.

11.11.2 Protection Related to Mechanical Problems

11.11.2.1 Sleeve Bearing Overtemperature

Gradual or sudden unexplained increases in the temperature of sleeve bearings should be investigated. Temperatures above normally acceptable values should be annunciated. Bearing temperature detectors should be located with the sensing element in close proximity to the babbitt metal. Bearing temperature detectors are usually RTDs or thermocouples.

11.11.2.2 Antifriction Bearing Problems

Antifriction bearings of the ball or roller type do not lend themselves to meaningful overtemperature protection. The temperature detectors must be located at the stationary race, and, by the time the temperature of the race is elevated, serious damage may already have occurred. It is recommended that vibration detectors be used to detect possible problems in antifriction bearings.

11.11.2.3 Machine Vibration

Drives that are susceptible to high vibration should have vibration detectors arranged to annunciate before serious damage is incurred.

11.11.3 Synchronous Motor Protection

The few large, low-speed, salient pole synchronous motors applied in generating stations are usually protected with methods and techniques similar to those for the large induction motors. A power factor relay is applied to protect the motor from operating below synchronous speed with the field applied. This out-of-synchronism or out-of-step operation causes pulsations in the stator current and the power factor rapidly becomes lagging. When the power factor relay senses abnormally lagging power factor, the field excitation is removed and the motor may be tripped.

11.11.4 Bus Transfer Protection

Excessive motor winding forces and high transient torques can result from bus transfer (throwover) operations in which the phase angle between the incoming source voltage and the motor residual fluxes is significant, and the motor residual flux has not decayed sufficiently. Care should be exercised when selecting the method of transfer with respect to motor capability, motor and load characteristics, circuit breaker operating times, and relative phase angle between the power sources. A more complete discussion of bus transfer is located in 11.10.3.

For high-speed transfer operations where the source voltages may not be in phase, consideration should be given to application of phase-angle relays that would block a high-speed transfer if the angle between the sources were such that excessive duty might be imposed on the motors if the transfer were completed.

Special voltage relays, which are not affected by the decaying frequency, are used to monitor auxiliary bus voltage during residual-voltage bus transfer operations to ensure that the incoming source circuit breaker does not close when significant flux levels exist in the motors.

11.12 Effects of Special Requirements on Motor Characteristics

Special requirements outside of the NEMA and ANSI Standards can have an effect on motor characteristics and physical size. Typical effects are presented below. Whether or not the special requirements have any significant effect, or the amount of any given effect, depends on the particular motor being considered and the combination of special requirements.

11.12.1 Low-Voltage Starting and/or High Starting Torque

The requirement to start and accelerate a particular load at low voltage may require that the motor be designed for higher than normal starting torque. The higher starting torque design normally would have a higher starting current. The machine may be somewhat oversize and have increased thermal capability. The efficiency of the motor may be higher. If there is a specified starting current limitation, and the higher torque design would result in starting current that exceeds the specified value, the higher starting torque might be achieved with a high-resistance rotor winding. This will result in higher slip operation under load, and the attendant increase in rotor losses may result in lower than standard efficiencies.

11.12.2 Capability of Accelerating High Inertia Load

It will usually be necessary to build an oversize motor for load inertias (WK^2) greater than the normal load inertias tabulated in NEMA MG1-1987 [7] and ANSI C50.41-1982 [1]. The increased size is required to provide the additional thermal capacity and, sometimes, torque to successfully accelerate the high load inertia. This usually results in higher starting current (see low starting voltage in 11.12.1 above) and lower power factor than usual and may result in lower motor efficiency.

11.12.3 Low Starting Current

Lower starting current might be achieved by reducing the physical size of the motor. This will usually result in lower breakdown torque capability, lower thermal capability, and a reduction in load inertia accelerating capability. It may be necessary to increase the rotor winding resistance in order to provide adequate starting torque. The motor efficiency will usually be lower, particularly if high rotor resistance is required for starting torque.

11.12.4 High Ambient Temperature

Capability for high ambient temperature (higher than 40 °C) can be achieved with two basic design changes. One method is to increase the physical size of the machine, particularly the conductor cross-sections, to provide lower temperature rise under load. Another method is to use a Class B temperature rise design with Class F insulation. The Class B design (with Class F insulation), operated at higher temperature, will result in higher winding resistance (due to the temperature), thus reducing the motor efficiency. In either case, the total temperature (ambient plus rise) must be within the total temperature rating of the insulation and bearings. Bearings for high-speed machines (1800 and 3600 r/min) may require flood lubrication to cool the bearing oil in order to limit the operating temperatures.

11.13 Effects of Exceeding Specified Motor Capabilities

The actual effect of exceeding motor capability stated in industry standards, or exceeding capability as stated in purchase specifications, depends upon the specific motor. To determine the effects on a specific motor, the motor manufacturer should be consulted. The following comments are general in nature and relate the exceeding of specified capability to physical effects. They are not intended to imply specific limits. Only the respective motor manufacturer can provide guidelines for extended operation outside specified capabilities. Not all possible operating situations are discussed.

11.13.1 Mechanical Overload

Mechanical overloading of a motor produces mechanical stresses that are higher than those expected for normal continuous operation. These stresses occur in all parts of the motor. The coupling, shaft, rotor spider, rotor winding, stator winding, stator core, stator frame, and foundation are all involved. The motor current increases with load, and the windings, stator core (iron), and rotor core (iron) will experience higher temperature rise that, at overload, may exceed the rated temperature rise. If the motor is operating in its maximum rated ambient temperature, the overload may result in the total temperature rating of the insulation system being exceeded. Insulation system life is adversely affected by high temperature. While operating at overload, the motor has less torque margin for riding through voltage dips.

During starting (particularly for low-voltage starting and/or high torque or high inertia loads), mechanical overload (higher load torque) will result in increased, or even excessive, heating and may lead to a stalled condition.

11.13.2 Continuous Operating Voltage

Operation at high voltage will result in a lower load component of current. The magnetizing current, however, will be higher. If the voltage is high enough, the increase in magnetizing current will more than offset the reduction in load current. This will result in higher copper loss and lower efficiency. The stator core loss will be increased due to the higher magnetizing flux, also causing a reduction in efficiency. High core loss and high magnetizing current can lead to high temperatures, resulting in reduction in insulation life. At high voltage, the power factor is reduced at high loads.

Operation at low voltage will require an increase in current to maintain load. The higher current will result in higher copper loss and higher winding temperature. Extended operation at voltages below the specified minimum can shorten insulation life. The stator core loss will be reduced. There might be a net decrease in efficiency, particularly at high load levels. At low voltage, power factor is reduced at low loads. Reduced voltage operation also results in a slight increase in slip.

11.13.3 Operation Outside Specified Frequency Variation

An increase in frequency will cause the machine to operate at higher speed. For variable and constant torque loads, the power required by the load and, therefore, the current will increase if the frequency increase is not accompanied by a corresponding voltage increase. Increase in frequency beyond the specified limit may result in high winding temperature due to the increase in current.

Operation at low frequency results in a reduction in speed that will unload the motor for variable and constant torque loads. If the voltage is not reduced along with the frequency, the motor flux increases, resulting in an increase in core heating. Operation at frequency below the specified limit can result in overexcitation of the machine.

11.13.4 High Ambient Temperature

Operation of a motor at rated load, in an environment with ambient temperature higher than that for which the motor is designed, can result in temperatures that exceed the rating of the insulation system (see 11.12.4 above). Extended operation at high ambient temperature usually requires derating of the motor (reduced load operation).

11.13.5 Starting Voltage Below Specified Minimum

Attempting to start and accelerate a motor with terminal voltage below the specified minimum value may result in insufficient torque to accelerate the motor and load. As a minimum result, the motor will experience increased heating due to longer accelerating time whether or not the motor torque is sufficient to accelerate the load. The stall and failure to start protective relaying may act to deenergize the machine, depending upon the severity of the prolonged acceleration resulting from the depressed voltage.

11.13.6 Excessive Frequency of Starting

Paragraph 11.8.4 presents information on repetitive starting capability. Exceeding the repetitive starting standards or special capability of a given machine will result usually in overtemperature and possible damage to stator and/or rotor windings. For frequent starting and regularly ignoring the recommended starting limitations, mechanical damage of a fatigue nature may occur. These types of damage are likely to accumulate over a long period of time. There have been instances in which adjustments were being made to driven equipment in which motors have been subjected to many starts in a short period of time resulting in motor failure during the procedure.

11.14 Motor Enclosures

11.14.1 Enclosure Definitions

Enclosures are defined and described in NEMA MG1-1987 [7], Sections 1.25, 1.26, and 1.27.

11.14.2 Motor Enclosure Application in Power Plant Environment

Motor enclosures suggested for enclosed (indoor) coal-fired plants are

	Area	Motor Enclosure
(1)	Turbine-generator building	ODP
(2)	Boiler area	ODP,DIP,EXP
(3)	AQC system (air quality control-scrubbers)	TEFC and TENV
(4)	Ash handling	TEFC and TENV
(5)	Coal handling	TEFC, DIP, EXP and TENV
(6)	Cooling towers or intake structure — condenser cooling water supply	ODP

NOTE — For outdoor installations, WPI, WPII, or TEWAC enclosures should be considered for applications in which ODP enclosures are normally applied for indoor installations.

ODP	= open, drip proof
TEFC	= totally enclosed, fan cooled
DIP	= dust ignition proof
EXP	= explosion proof
TENV	= totally enclosed, nonventilated — for smaller motors
WPI, WPII	= weather protected
TEWAC	= totally enclosed, water-to-air-cooled

Definite recommendations cannot be made for the hazardous (classified) areas that may be encountered in the pulverizer and burner areas at the coal handling system. The hazard is caused either by coal dust in the air or by methane gas generated by the decomposition of the coal. Each area should be carefully analyzed as to classification, and the proper equipment enclosure should be applied. It is also possible to eliminate the use of expensive equipment for hazardous areas by ventilating or pressurizing the electrical equipment areas. The National Electrical Code, NFPA 70-1990 [3] published by the National Fire Protection Association is usually used as the basis for selecting equipment for hazardous (classified) locations. The National Electrical Safety Code, ANSI C2-1990, also provides guidance for hazardous (classified) areas found in and around generating stations.

ODP motors above selected ratings should be equipped with space heaters, which are to be energized when the motors are not running, to prevent condensation in the machines when they cool following operation, during idle periods, or during storage. TEFC motors should have drain plugs, but they should not have space heaters.

11.15 Motor Bearings

Small horizontal motors of the NEMA class (up to about 200 hp) use antifriction bearings. The major motor manufacturers have standardized on this type bearing. ANSI C50.41-1982 [1] permits either antifriction or sleeve type bearings through 1500 hp and requires split sleeve and split bearing brackets above that rating. Utilities usually use sleeve or split sleeve bearings starting at about 200 hp.

Antifriction bearings have a rating life (L_{10}), which is the life in millions of revolutions (years can be used) that 90% of a group will exceed. Fifty percent will exceed approximately five times the rating life. Refer to ANSI/AFBMA 9-1990 [2] for exact definition. In order to reduce bearing failures, a satisfactory rating life should be specified.

Sleeve bearings with oil ring lubrication do not have a life rating and are considered, by some, to have infinite life based on proper installation, alignment, maintenance, and absence of damaging vibrations. This is the main reason for the preference for this type. These bearings, as usually applied, have no thrust ability, and the shaft journal must float

in the bearing such that the journal shoulders do not touch the shoulders of the bearing. This is accomplished by using limited end float couplings (or equivalent) on the shaft and also by having the driven equipment accept its own thrust with limited movement.

Sleeve bearings on very large motors may require forced lubrication (see manufacturer's information for ratings). The oil rings usually are included so that there is some lubrication upon failure of the forced lubrication system. Forced lubrication systems may be purchased with the motor (a separate power source is required) or, as in the usual case, a common system for the driven equipment and the motor may be used.

Small standard, horizontal motors typically have antifriction bearings with a rating life of 25 000 h for belted applications and 100 000 h for direct connected loads. Horizontal motors applied on drives that have significant side thrust, such as belted sheave drives, normally have antifriction bearings that have higher side thrust capability than sleeve bearings.

Vertical motors usually have the thrust bearing for the motor and the driven equipment. This bearing must support the weight of the motor rotor, the driven equipment rotor (impeller), and also any vertical thrust from the driven equipment, such as the pressure from a column of fluid. For pumps such as the axial flow type, which may operate with a closed discharge, the bearing must be designed to withstand this additional thrust for the time the shut-off condition will exist. In addition, some pumps will develop up-thrust, and additional measures must be provided for this condition.

Vertical motors are made with both solid and hollow shafts. On hollow shaft motors, the pump shaft is secured to the motor at the thrust bearing, and, in some instances, this connection can be unscrewed by reverse rotation. Devices that prevent reverse rotation or self-release couplings are available.

Small vertical motors use angular contact or spherical roller antifriction thrust bearings, depending on the thrust and preference. These bearings usually have a rating life of one year and an average life of approximately five years, unless higher values are specified. Refer to manufacturer's information for explanation of thrust capability. Large vertical motors such as condensate pump and circulating water pump motors may have antifriction or plate-type bearings. The plate type has practically unlimited life if properly applied which is the major advantage. The plate-type bearing is usually more expensive, has higher losses, and usually requires water cooling.

Motor protection information related to bearings is included in 11.11.2.

11.16 Maintenance

Preventive maintenance, including inspection, testing, and monitoring of machine components such as windings and bearings, plays an important role in maintaining high levels of reliability and availability. Other maintenance related factors, such as ability to repair and stocking of repair and renewal parts, can also contribute to high levels of availability.

Manufacturer instruction manuals are the most important source of preventive maintenance recommendations and procedures. Excellent industry wide references on the subjects of proper installation, preventive maintenance, repair and recommended spare parts include references [3], [8], and [11].

11.17 Relationships Used in AC Motor Performance and System Calculations

Shaft horsepower:

$$P_M = \frac{T \cdot N}{5252} \quad (11.5)$$

where

P_M is shaft power in horsepower
 T is torque in lb-ft
 N is speed in revolutions per minute

Motor electrical input:

$$S = V_{L-L} I_L \text{ for three phase machines}$$

where

S is the apparent power in kVA
 V_{L-L} is the three phase line-to-line voltage in kV
 I_L is the line current in A

also,

$$S = \frac{P_M \cdot .746}{\eta \cdot F_p}$$

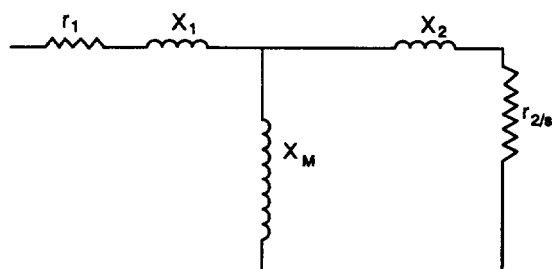
where

η is the per unit efficiency
 F_p is the per unit power factor
 P_M is the mechanical power in hp

For per unit calculations, the base S (kVA) of the machine should be determined using the nameplate V (kV) and current, or the nameplate hp and the efficiency and power factor at nameplate hp.

11.17.1 Induction Motor Equivalent Circuit

The basic induction motor equivalent circuit is shown in Fig 11.41. The values of equivalent circuit resistances and reactance can be used for many performance and system calculations. The values are expressed in ohms per phase or in per unit on the motor kVA base. Reference [9] contains a detailed discussion and description of the equivalent circuit.



- r_1 = stator dc resistance per phase corrected to operating temperature
- r_2 = rotor resistance per phase at rated speed and operating temperature referred to stator
- X_1 = stator leakage reactance per phase at rated current
- X_2 = rotor leakage reactance per phase at rated speed and rated current referred to stator
- X_M = magnetizing reactance per phase
- s = slip, in pu, of synchronous speed

Figure 11.41 — Induction Motor Equivalent Circuit

The values of the induction motor equivalent circuit components are not constant for all performance calculations. The rotor resistance can vary significantly between locked rotor conditions (zero speed) and full running speed due to the skin effect caused by the relatively high rotor frequency at low speed. The rotor resistance at locked rotor can be as much as 2–5 times greater than the running value, depending on the rotor bar shape and configuration. The high motor current at low speed results in saturation effects that cause the rotor leakage reactance to have a lower value than at full speed. The stator leakage reactance is only slightly reduced. The magnetizing reactance will change for wide variations in terminal voltage. This effect is neglected usually for the voltage range between 75–110% of rated voltage, for most performance calculations. The resistances also vary with winding temperature. When requesting equivalent circuit data from manufacturers, running and/or locked rotor values should be specified.

The per unit locked rotor impedance can be estimated as

$$Z_{LRPU} = \frac{1}{I_{LRPU}} = \frac{\text{Full Load Current}}{\text{Starting Current}}$$

Definitions and expressions for induction motor time constants are presented in Section 1.59 of NEMA MG1-1987 [7].

Torque can be calculated from the equivalent circuit using the appropriate values for the circuit components in the following expression:

$$T = i_2^2 \frac{r_2}{s}$$

where

- T = torque in pu on the kVA base
- i_2 = per unit rotor current calculated from the equivalent circuit at the desired value of per unit terminal voltage
- r_2 = per unit rotor resistance at the speed being considered
- s = per unit slip (per unit slip = [1 - per unit speed])

Note that the torque calculated from the equivalent circuit is expressed in pu on the machine input kVA base. When comparing this value to load torque or motor torque expressed on the output horsepower base, the following relationship must be observed:

$$kVA = \frac{(T_{hp})(hp_{base})(0.746)}{kVA_{base}}$$

where

$$\begin{aligned} T_{kVA} &= \text{per unit torque on the motor input kVA base} \\ T_{hp} &= \text{per unit torque on the torque base determined from Eq (11.5) at nameplate horsepower and nameplate speed} \\ hp_{base} &= \text{motor nameplate horsepower} \\ kVA_{base} &= \text{motor three phase kVA determined at nameplate voltage and nameplate current} \end{aligned}$$

11.17.3 Motor and Driven Equipment Acceleration

A motor will accelerate its load if the motor developed torque is greater than the load torque. The time to accelerate from one speed to another speed is directly proportional to the inertia (WK^2) of the motor rotor and load and the change in speed, and is inversely proportional to the accelerating torque. The accelerating torque is the difference between the motor developed torque and the load torque. To calculate the accelerating time, the following expressions can be used:

$$\Delta t = \frac{WK^2 \cdot \Delta N}{308} \cdot \left(\frac{1}{T_A} \right) \text{ average} \Big|_{\Delta N}$$

where

$$\begin{aligned} \Delta t &= \text{time, in s, to accelerate } \Delta N \text{ r/min} \\ WK^2 &= \text{total motor and load inertia in lb}\cdot\text{ft}^2 \\ T_A &= \text{the accelerating torque in lb}\cdot\text{ft} \\ \left(\frac{1}{T_A} \right) \text{ average} \Big|_{\Delta N} &= \text{the average of the reciprocals of the accelerating torques for the speed change } \Delta N \end{aligned}$$

If it is desired to calculate the accelerating time using per unit quantities, the following expression can be used:

$$\Delta t = 2.68H\Delta N \cdot \left(\frac{1}{T_A} \right) \text{ average} \Big|_{\Delta N}$$

where

$$\begin{aligned} \Delta t &= \text{time, in s, to accelerate } \Delta N \text{ in pu of synchronous speed for an ac motor} \\ T_A &= \text{accelerating torque in pu of rated torque determined at motor rated horsepower and speed} \\ H &= \text{inertia constant} \\ H &= H = \frac{(.231)(WK^2)(N)^2}{(hp_{base})(10^6)} \end{aligned}$$

where

$$\begin{aligned} WK^2 &= \text{total inertia of the motor rotor and load in lb}\cdot\text{ft}^2 \\ N &= \text{synchronous speed of the motor in r/min} \\ hp_{base} &= \text{rated horsepower of the motor} \end{aligned}$$

Since both the motor developed torque for ac motors and the torque for most loads vary with speed, the accelerating torque will not be constant for acceleration over a wide speed range. In order to calculate accelerating time with any degree of accuracy, it is necessary to divide the total speed change into increments and sum the accelerating times of the individual speed change increments (refer to Fig 11.42).

It is important to take into account the effect of any changes in motor terminal voltage on the motor developed torque during acceleration. Motor starting voltage dips can have a significant effect on the accelerating torque and, therefore, the accelerating time.

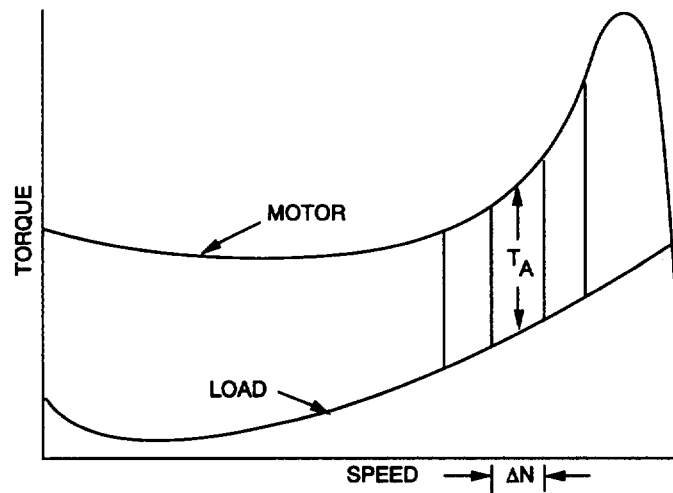


Figure 11.42 — Motor Torque, Load Torque, and Average Accelerating Torque, T_A , for Speed Change Increment, ΔN

12. Cables and Other Conductors

12.1 Introduction

This section is a guide for the selection and application of insulated cables and nonsegregated phase bus. Additional information is available in IEEE Std 422-1986 [9]²⁵ and Chapter 11 of IEEE Std 141-1986 [7].

12.2 References

- [1] AEIC CS5-1987, Specification for Thermoplastic and Cross-Linked Polyethylene Insulated Shielded Power Cables Rated 5 through 46 kV.²⁶
- [2] AEIC CS6-1987, Specification for Ethylene Propylene Rubber Insulated Cables Rated 5 through 69 kV.
- [3] ICEA P-32-382-1969, Short Circuit Characteristics of Insulated Cable.²⁷
- [4] ICEA P-34-359-1958 (Reprint 1973), Committee Report on AC/DC Resistance Ratios at 60 Cycles.
- [5] IEEE C37.24-1986, IEEE Guide for Evaluating the Effect of Solar Radiation on Outdoor Metal-Enclosed Switchgear (ANSI).²⁸
- [6] IEEE S-135, IEEE/IPCEA Power Cable Ampacities.
- [7] IEEE Std 141-1986, IEEE Recommended Practice for Electric Power Distribution for Industrial Plants (ANSI).
- [8] IEEE Std 383-1974 (Reaf 1980), IEEE Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations (ANSI).
- [9] IEEE Std 422-1986, IEEE Guide for the Design and Installation of Cable Systems in Power Generating Stations (ANSI).
- [10] IEEE Std 532-1982, IEEE Guide for Selecting and Testing Jackets for Cables (ANSI).
- [11] NEMA WC 3-1980 (Reaf 1986), Rubber-Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy (ICEA S-19-81 Sixth Edition).²⁹
- [12] NEMA WC 5-1973 (Reaf 1979, 1985), Thermoplastic-Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy (ICEA S-61-402 Third Edition).
- [13] NEMA WC 7-1988, Cross-Linked-Thermosetting-Polyethylene-Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy (ICEA S-66-524).
- [14] NEMA WC 8-1988, Ethylene-Propylene-Rubber-Insulated Cable for the Transmission and Distribution of Electrical Energy (ICEA S-68-516).
- [15] NEMA WC 51-1986, Ampacities of Cable in Open-Top Cable Trays (ICEA P-54-440 Third Edition).

²⁵The numbers in brackets correspond to those of the references listed in 12.2.

²⁶AEIC publications are available from the Association of Edison Illuminating Companies, 600 N. 18th Street, P.O. Box 2641, Birmingham, AL 35291-0992, USA.

²⁷ICEA publications are available from ICEA, P.O. Box 411, South Yarmouth, MA 02664, USA.

²⁸IEEE publications are available from the Institute of Electrical and Electronics Engineers, Service Center, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA.

²⁹NEMA publications are available from the National Electrical Manufacturers Association, 2101 L Street NW, Washington, DC 20037, USA.

- [16] *Electrical Transmission and Distribution Reference Book*, Westinghouse.
- [17] El-Kady, M.A. and Horrocks, D. N. "Extended Values for Geometric Factor for External Thermal Resistance of Cables in Duct Banks," *IEEE Transactions on Power Apparatus and Systems*. vol. PAS-104, pp. 1958–1962, 1985.
- [18] Engmann, G. "Ampacity of Cable in Covered Tray," *IEEE Transactions on Power Apparatus and Systems*. vol. PAS-103, pp. 345–350, 1984.
- [19] Engmann, G. "Cable Ampacity in Tray with Raised Covers," *IEEE Transactions on Energy Conversion*. vol. EC-1, pp. 113–119, 1986.
- [20] Engmann, G. "Low Voltage Cable Ampacity with Four or More Conductors in Rigid Galvanized Steel Conduit," *IEEE Transactions on Power Apparatus and Systems*. vol. PAS-101, pp. 3201–3205, 1982.
- [21] Flatabo, N. "Transient Heat Conduction Problem Solved by the Finite Element Method," *IEEE Transactions on Power Apparatus and Systems*. vol. PAS-92, pp. 161–168, 1973.
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- [25] Stolpe, J. "Ampacities for Cable in Randomly Filled Trays," *IEEE Transactions on Power Apparatus and Systems*. vol. PAS-90, pp. 962–973.

12.3 Insulated Cable

Cables are classified into three categories in accordance with their applications:

- 1) Power cable
- 2) Control cable
- 3) Instrumentation cable

In this guide, single or multiconductor insulated cables used to supply electric power are grouped by insulation class as follows:

- 1) Low voltage — 600 V or less
- 2) Medium voltage — 601 V to 15 000 V
- 3) High voltage — over 15 000 V

Control cables are applied at relatively low current levels or used for intermittent operation to change the operating status of a utilization device of the plant auxiliary system.

Instrumentation cables are used for transmitting variable (analog) current or voltage signals or for transmitting coded information (digital).

12.3.1 Service Conditions

When specifying cables for installation in generation stations, the service conditions under which the cable will operate during its life span should be considered.

The following conditions should be considered in the application of a specific cable:

- 1) Circuit voltage
- 2) Load current
- 3) Available fault current
- 4) Circuit grounding
- 5) Chemical and corrosive atmosphere
- 6) Blowing sand or dust
- 7) Presence of sulfur and crude oil vapors
- 8) Presence of atmospheric ozone
- 9) Ambient temperatures
- 10) Sun and radiation exposure
- 11) Underground and above ground installations
- 12) Cable tray installation
- 13) Direct burial applications
- 14) Wet or dry locations
- 15) Other indoor and outdoor environments
- 16) Probable exposure fires
- 17) Interaction with magnetic materials
- 18) Animal and insect attack

In addition to the operating environment, the environmental conditions during installation and the installation methods should be considered in selecting a cable.

12.3.2 Cable Application Criteria

Proper identification of the design limits will ensure the highest reliability. A cable system should have a service life equal to or better than the equipment it serves.

Insulating material temperature should not adversely effect insulating properties. The cable should maintain its required insulating properties for its service life when installed in wet locations, especially underground. The cable should maintain its required insulating properties when exposed to chemical environments. The cable materials should be stable when exposed to the deteriorating effects of ultraviolet and infrared exposure from the sun or other sources of radiation.

Cables installed in open or enclosed cable trays, wireways, or in other raceway systems where flame propagation is of concern should pass the applicable flame test requirement of IEEE Std 383-1974 [8].

The cables should be capable of withstanding anticipated physical impact as well as compressive or tensile stresses to which they may be exposed without adversely effecting their integrity.

12.3.3 Cable Terminology

Listed below are terms commonly encountered in cable engineering literature and a brief description of their meaning.

thermal resistivity (RHO): The unit of thermal resistivity of a certain material (RHO) is the temperature difference between two faces of a 1 cm cube when 1 W flows through it. An RHO of 90 °C-cm/W means that the temperature difference between two opposite faces of a cube in the direction of the heat flow is 90 °C when 1 W of heat is flowing through it.

insulation power factor: The term *power factor* in cable work is not to be confused with load power factor in the conductor. Insulation power factor is the ratio of dielectric loss to total apparent power due to charging current, which is equivalent to real power loss in the insulation divided by apparent power.

cable capacitance: The conductor and the shield, separated by a dielectric, comprise a uniformly distributed shunt capacitor on the power system. The capacitance is a function of the dielectric constant and the construction of the cable. Conductor-to-conductor capacitance is also encountered in nonshielded cable applications.

cable charging current: A cable is a long shunt capacitor. A charging current flows when the cable is energized with ac voltage. Since the voltage is ac, the charging current flows continuously. The charging current is independent of load current.

cable dielectric loss: Dielectric losses are produced by the charging current flowing in or out of the cable insulation. It is a product of voltage, charging current, and the power factor of the insulation.

ac/dc ratio: This ratio indicates the increase in effective resistance of a conductor when carrying ac currents. It includes skin effects and proximity effects for multiple conductor arrangements. For additional information, see Neher and McGrath [22] and ICEA P-34-359-1958 [4].

conductor loss: The conductor loss is the total current loss due to conductor and shield resistance. When no shield losses are involved, the conductor loss is the main source of generated heat. Dielectric losses are not usually significant.

shield currents, voltages, and losses: The electromagnetic field generated by the load current induces a voltage in the shield. On a shielded system, grounded at one point, the shield voltage increases in the direction away from the ground point. The magnitude of the voltage at any one point is a function of the load current conductor voltage and the distance from the ground point.

load factor: Load factor is the ratio of the average load over a designated period of time to the peak load occurring in that period. It is an indication of the reduction in the cable loss, attributed to load current, from the loss that would be generated if the peak were continuous. In underground installations, the load factor is significant because of the large thermal capacity of the surrounding earth; thereby creating a time lag between temperature rise of the cable and the temperature rise of the surroundings. The net result is a higher permissible current rating for underground cables that do not carry full load continuously.

circular mil (cmil): A unit of area equal to $\pi/4$ of a square mil (mil^2) (0.7854 mil^2). The cross-sectional area of a circle in circular mils is therefore equal to the square of its diameter in mils. A circular inch is equal to 1 million mil^2 . For convenience, conductor sizes are usually expressed in thousands of circular mils (kcmil).

12.3.4 Cable Components

The common components used to make up a cable are the conductor, conductor shield, insulation, insulation shield, and jacket. The NEMA and AEIC standards include additional information on cable components. For example, see references [1], [2], and [11]–[14].

The conductors used in power plants can be either solid or stranded, depending on the cable flexibility desired. There is a wide variety of stranding, each designed for a specific purpose. The commonly used materials for conductors in cable construction are copper and aluminum. Annealed copper offers excellent electrical and mechanical properties at reasonable cost. Aluminum has 61% of the conductivity of copper, but it has less than one third the density. For equal current carrying capacity, the weight of aluminum is 48% that of copper. Aluminum may cold-flow or oxidize rapidly, and, when connected to copper, may develop galvanic corrosion. Aluminum also has a relatively large coefficient of thermal expansion.

The conductor shield provides a neatly uniform voltage plane around the strands and eliminates high concentrations of voltage stress at the voids between conductor strands and the insulation. The shield is a wrapping of a semiconducting tape or extrusion of a semiconducting material over the strands before insulation is applied. A solid, round conductor would need no conductor shielding. The need for conductor shielding increases with voltage rating. It is usually required on cables rated 5 kV and over.

The insulation of a cable is that part that insulates the conductors from other conductors, from conducting parts, or from ground. The following qualities comprise a good cable insulating material:

- 1) High dielectric strength
- 2) Low power factor
- 3) Resistance to oxidation
- 4) Resistance to ozone
- 5) Low moisture absorption
- 6) Uniformity of composition
- 7) Good aging properties
- 8) High resistance to thermal damage
- 9) Flame retardance
- 10) Acceptable chemical decomposition when burned

Historically, the commonly used insulating materials used to be natural rubber and varnished, cambric impregnated paper. In modern generating stations, power cable insulating materials are usually cross-linked polyethylene (XLP) and ethylene propylene rubber (EPR).

The purpose of the insulation shield is to provide a uniform voltage gradient around the insulation. The shield produces symmetrical radial voltage gradients that relieve the high stress areas in the insulation and reduce external stresses. In unshielded cables, the voltage, either between phases or to ground, divides itself in relation to the absolute capacitivities of the dielectrics in the voltage path. This may result in distorted dielectric fields and voltage concentrations within and external to the insulation.

The insulation shield is applied over the insulation either as conducting or semiconducting tape or semiconducting extrusion.

In all installations, it is good practice to apply a jacket over the shield to protect metallic shielding and cable insulation from mechanical damage during cable installation. Commonly used jacketing materials are neoprene, chlorosulfanated polyethylene (hypalon), chlorinated polyethylene (CPE), polyethylene, and PVC. The jacket also protects the shielding from electrolytic or galvanic corrosion. Jacket material should be flame retardant.

See IEEE Std 532-1982 [10] for additional guidance in the selection of cable jacket material.

12.3.5 Cable Characteristics

Certain characteristics of cables are important to the selection of cables for a specific application.

The cable dimension is dependent on the number of conductors, stranding, insulation and jacket thickness, and other design parameters. ICEA³⁰ standards can be used to calculate minimum diameter. Manufacturers' catalogs sometimes give the nominal diameter of a specific cable.

Conductor resistances at various conductor operating temperatures can be determined from ICEA standards and from IEEE S-135 [6].

Reference [16] shows how a conductor series inductive reactance may be determined, in ohms per 1000 ft, based on conductor size and spacing. Reactance values used for calculating voltage drop (regulation) and circuit impedance for short-circuit calculations may be obtained from [16].

³⁰Insulated Cable Engineers Association, P.O. Box 411, South Yarmouth, MA 02664, USA.

12.3.6 Cable System Design

Cable system design in generating stations is usually based on ambient air and surrounding surface temperatures of 40 °C and on earth temperatures of 20 °C. Special consideration must be given to cables installed in plant areas where ambient temperatures may exceed 40 °C, such as steam generator burners and penthouses, reactor containments, roof areas, etc. In these areas, cables with special high temperature insulations should be considered.

For most applications, it is suggested that annealed, stranded, copper conductors be used for power cables. It is also suggested that the individual strands be coated with tin, lead, or lead alloy, or that a separator over the conductor be used. The strand shield or insulation in direct contact with the conductor may corrode the conductor.

The insulation wall thickness specified for a particular application is dependent on system voltage, conductor size, insulating material, and the percent insulation level. References [1], [2], and [11]–[14] give minimum insulation thicknesses for cables.

Rigid rules can not be established for universal application of cable configurations in generating station applications, but some typical configurations are given in Table 12.1.

Cable ampacity, voltage regulation, shield currents, short circuit duty, and mechanical strength should be considered in the selection of conductor size.

Power cables rated 5 kV and over should be equipped with insulation shield. Shielding usually is not required for control cables. Low level signal cables should be twisted and shielded where reduction of electrical noise is important. All shields should be grounded at least at one point. See IEEE Std 422-1986 [9] for additional information on cable shields.

Table 12.1 — Typical Cable Configurations

Voltage Class	Conduit, Duct, or Tray Installation
5 kV and above	1/c shielded
600 V Power	3/c #12 AWG to #2 AWG, 1/C #1/0 and larger, nonshielded
600 V Control	Multiconductor #14 AWG
600 V and 300 V Instrument	Twisted and untwisted multiconductor #16 AWG shielded (note current transformer circuits typically have larger conductors)
600 V and 300 V Thermocouple Extension Wire	Single pair and multipair #16, shielded

12.3.6.1 Cable System Calculations

The following are typical equations for cable system quantities:

Conductor losses may be calculated from

$$W_c = I^2 R$$

where

$$W_c = \text{loss per-unit length (in W/m)}$$

I = load current (in A)
 R = resistance per meter (in Ω /m)

Capacitive reactance may be calculated from

$$X_c = \frac{1}{2\pi(fC)}$$

where

X_c = capacitive reactance (in Ω /m)
 C = capacitance (in F/m)
 f = frequency (in Hz)

Charging current may be calculated from

$$I_c = \frac{E_o}{X_c}$$

where

I_c = charging current (in A)
 E_o = line-to-ground voltage (in V)
 X_c = capacitive reactance (in Ω)

Dielectric loss may be calculated from

$$W_d = E_o I_c PF$$

where

W_d = dielectric loss (in W/m)
 E_o = line-to-ground voltage (in V)
 I_c = charging current per foot (in A/m)
 PF = power factor of insulation

Voltage drop may be calculated from

$$V_d = I(R \cos \theta + X \sin \theta)$$

where

V_d = voltage drop (in V)
 I = load current (in A)
 R = ac resistance (in Ω)

12.3.6.2 Ampacity

Insulated power cable ampacity can be determined by the use of methods given in references [17], [21]–[23], and [25]. The design parameters used in the calculation of cable ampacity include ambient temperature (air or earth), thermal conductivity of surrounding media, maximum allowable temperature for the cable insulation, shielding and jacket material, and conductor resistance.

In general, power cable conductor continuous ampacity should equal or exceed the long-time trip rating of the overcurrent protection. Where overcurrent alarms are used to annunciate moderate overcurrent, the short-time emergency rating may be used to determine the overcurrent protection trip setting.

The power cable ampacities required for through fault and momentary-load currents, short time continuous loads, and long time continuous operation are discussed in the following sections.

12.3.6.2.1 Through Fault and Momentary Ampacity

The through fault current carrying capability may be determined from ICEA P-32-382 [3]. However, cable systems need not be designed to carry through fault current without exceeding maximum conductor temperatures. For feeder cables, through fault currents occur because of load equipment failure. When this occurs, the feeder cable integrity may be ascertained. Design for through fault current withstand capability is an economic consideration.

The through fault capability of cable in ICEA P-32-382 [3] is based on the following formulas:

Copper conductor:

$$(I / A)^2 t = 0.0297 \log_{10} \frac{T_2 + 234}{T_1 + 234}$$

where

- I = through fault current (in A)
- A = conductor area (in cmil)
- t = through-fault duration (in s)
- T_1 = prefault conductor temperature (in °C)
- T_2 = maximum through fault conductor temperature (in °C)
 - = 200 °C for paper, rubber, and varnished cambric insulation
 - = 150 °C for thermoplastic insulation
 - = 250 °C for cross-linked polyethylene and ethylene propylene rubber insulation

Aluminum conductor:

$$(I / A)^2 t = 0.0125 \log_{10} \frac{T_2 + 228}{T_1 + 228}$$

where

- I = through fault current (in A)
- A = conductor area (in cmil)
- t = through fault duration (in s)
- T_1 = prefault conductor temperature (in °C)
- T_2 = maximum through fault conductor temperature (in °C)
 - = 200 °C for paper, rubber, and varnished cambric insulation
 - = 150 °C for thermoplastic insulation
 - = 250 °C for cross-linked polyethylene and ethylene propylene rubber

The formulas are based on the assumption that there is no transfer of the cable heat to the environment, and, therefore, the formulas are applicable to all types of installations, e.g., duct bank, direct burial, cable tray, and conduit.

These formulas may also be used to calculate momentary current carrying capability for duties such as motor-inrush current. However, normal momentary duties do not usually result in excessive cable temperatures.

12.3.6.2.2 Short-Time Continuous Ampacity

The short-time continuous ampacity can be calculated with the methods given in references [17], [21], [22], and [25]. The short time rating is determined with a maximum conductor temperature that is usually higher than the maximum temperature used for the continuous ampacity.

12.3.6.2.3 Continuous Ampacity

Each configuration of cable and raceway requires calculation of continuous cable ampacity for that particular configuration. The general categories for raceway and cable configuration are:

- 1) Cable in free air
- 2) Cable in above grade conduit and duct
- 3) Randomly laid cable in cable tray
- 4) Cable with maintained spacing in cable tray
- 5) Cable in wire way
- 6) Direct buried cable
- 7) Cable in underground conduit and duct

The heat generated in control and instrument cables due to signal voltage and currents is usually negligible, and cable ampacity need not be calculated. However, control and instrument cable installed in raceway with power cable should be considered in determining the power cable ampacity (see IEEE Std 422-1986 [9]).

The ampacity of cable installed in free air and in above grade conduit and duct can be determined from the methods presented in references [17], [21]–[23], or from IEEE S-135 [6]. For more than three conductors in above grade conduit, the method presented in reference [20] may be used.

Randomly laid cable in tray has an allowable ampacity that can be calculated from the methods presented by Stolpe [25] or from the tables that are given in NEMA WC 51-1986 [15]. Added guidance is given in IEEE Std 422-1986 [9]. IEEE Std 422-1986 [9] and Stolpe [25] recommend that power cable installed in a randomly filled tray with control cable have an allowable ampacity that is calculated as if all the cable in the tray were power cable.

The ampacity tables given in NEMA WC51 [15] are based on a maximum allowable heat generation calculated using the Stolpe method and IEEE S-135 [6]. Some of the ampacity values in the tables are limited to 80% of the free air rating given in IEEE S-135 [6]. The rest of the ampacity values are calculated from the Stolpe method maximum heat generation that is given in Table 12.2. The ampacity is calculated from the maximum heat generation using the following formula:

Table 12.2 — Maximum Heat Generation

Depth of Fill in (cm)	Maximum Heat Generation W / m ³
1.0 (2.54)	36900
1.5 (3.81)	22700
2.0 (5.80)	15400
2.5 (6.35)	11400
3.0 (7.62)	8750

$$I = \left(\frac{(s\pi r_w)^2}{nR} \right)^{0.5} \quad (12.1)$$

where

I	= maximum allowable ampacity (in A)
s	= maximum heat generation (in W/m ³)
π	= constant = 3.1416
r_w	= radius of cable in packed cable mass (in m)
n	= number of conductors in the cable in the packed cable mass (dimensionless)
R	= electrical resistance of a cable conductor in the packed cable mass (in Ω /m)

For larger conductors (greater than 1000 kcmil), the electrical resistance is the dc resistance modified for the ac skin effect. The ac/dc resistance ratios that account for this skin effect are given in ICEA P-34-359 [4]. For smaller conductors, the electrical resistance for cable conductors is the dc resistance of the conductor at the maximum operating temperature.

The allowable ampacity of cable in tray with tray covers can be calculated with the methods presented in [18] and [19]. Using those methods, factors can be developed for use with the allowable ampacities given in NEMA WC51-1986 [15] or calculated from Eq 12.1. Table 12.3 gives the factors that can be applied to open tray ratings to calculate the covered tray allowable ampacity.

Cable can be installed in cable tray with spacing that is maintained during operation by the use of spacers, tie downs, etc. Cable ampacity for such installations is obtained from IEEE S-135 [6].

Table 12.3 — Covered Tray Derated Ampacity Percent of Ampacities Listed in NEMA WC 51-1986 [5]

Cable Loading Depth in (cm)	3 in (7.62 cm) Tray	4 in (10.16 cm) Tray	5 in (12.7 cm) Tray
1.0 (2.54)	74%	74%	74%
1.5 (3.81)	74%	74%	74%
2.0 (5.08)	75%	75%	75%
2.5 (6.35)	75%	75%	75%
3.0 (7.62)	—	76%	76%

Ampacity of cable in wireway can be determined from the tables of NEMA WC51-1986 [15] or Eq 12.1. The method presented in references [18] and [19] and Table 12.3 may be used for cable in wireway with covers.

The methods presented by Neher and McGrath [22] or the ampacities given in IEEE S-135 [6] can be used to determine the ampacity of direct buried cable and cable installed in underground conduit and duct. Alternatively, finite element techniques, such as those presented in [17], [21], and [23] can be used.

Fire protection requirements at some installations lead to fire barriers in raceway at fire rated walls and floors. In addition, fire stops or fire breaks are sometimes installed on longer runs of vertical or horizontal raceway. The fire barriers and fire stops will cause a thermal gradient in the cable, and the effect on cable ampacity should be considered for cable in an open top cable tray. The factors presented in Tables 12.4 and 12.5 may be used with the NEMA WC51-1986 [15] or Eq 12.1 to determine the ampacity.

Table 12.4 — Firestop Derated Ampacity of Copper Conductor Cable Percent of Ampacities Listed in NEMA WC 51-1986 [15]

Depth of Fill in (cm)	Firestop Thickness, in (cm)			
	3.0 (7.62)	6.0 (15.24)	9.0 (22.86)	12.0 (30.48)
1.0 (2.54)	94%	91%	88%	85%
1.5 (3.81)	94%	91%	89%	87%
2.0 (5.08)	94%	92%	90%	88%
2.5 (6.35)	94%	92%	90%	89%
3.0 (7.62)	94%	92%	91%	90%

Table 12.5 — Firestop Derated Ampacity of Aluminum Conductor Cable Percent of Ampacities Listed in NEMA WC 51-1986 [15]

Depth of Fill in (cm)	Firestop Thickness, in (cm)			
	3.0 (7.62)	6.0 (15.24)	9.0 (22.86)	12.0 (30.48)
1.0 (2.54)	93%	90%	86%	82%
1.5 (3.81)	93%	90%	87%	84%
2.0 (5.08)	93%	91%	89%	86%
2.5 (6.35)	93%	91%	89%	87%
3.0 (7.62)	93%	91%	90%	88%

For some installations, raceway is wrapped with a fire protective wrap. This wrapping is a significant change in the thermal system configuration, and derating from the unwrapped ampacities is required. The curves given in Fig 12.1 can be used with [24] or Eq 12.1 to determine the ampacity of cable in wrapped cable tray. The ratio z/k is the ratio of the thickness of the wrap (meters) to its thermal conductivity (W/m-C), and e is the emissivity (dimensionless) of the outside surface of the wrap.

Cable with metallic shields can have the shield connected to ground at both ends of the cable. In this configuration, the shield will carry current that is induced by the conductor current. The methods presented by Neher and McGrath [22] and IEEE Std 422-1986 [9] can be used to determine the ampacity of cables with both shield ends grounded.

12.3.6.3 Voltage Regulation

The cables should be sized such that the minimum expected voltage at the load terminals is within the voltage rating of the load, or it has been determined (e.g., motor acceleration study) that the load will perform satisfactorily.

12.3.7 Installation Practice

The following are some fundamentals in design that have a direct bearing on construction limitations.

12.3.7.1 Raceway Systems

Generating plant interconnecting cables usually are installed in cable trays, above grade conduits and wireways, and below grade conduits.

A cable tray system is a unit or assembly of units or sections and associated fittings, made of metal or other material, forming a rigid structural system used to support cables. Cable tray systems include ladders, troughs, channels, solid bottom trays, and other similar structures.

An exposed conduit is a tubular metallic or nonmetallic raceway with integral or associated couplings, connectors, and fittings approved for the installation of electrical conductors. Rigid steel (RS), intermediate metal conduit (IMC), electric metallic tubing (EMT), flexible conduit, aluminum conduit, and polyvinylchloride are typical of the conduit types used in this service.

A wireway is a sheet; metal trough with hinged or removable covers for housing and protecting cables.

Refer to IEEE Std 422-1986 [9] for recommendations related to these types of raceway systems.

12.3.7.2 Physical Separation of Cable Classes in Trays

Medium-voltage power cables should be installed in raceways separate from low voltage power and control cables and low-level signal cables. In vertically stacked trays, the highest voltage cables should be in the highest position in the tray stack.

Control cables may be mixed with low-voltage power cables if the cable voltage ratings are equal, and their respective cable sizes do not differ greatly. When this is done in trays, the power cable should be derated as if all cables in the tray were power cable, unless position and grouping are controlled. Complete separation of control cable from power cable is also a common practice.

Low level digital signal cables may be run in control cable raceways, if this meets the requirements of the signal receiving equipment.

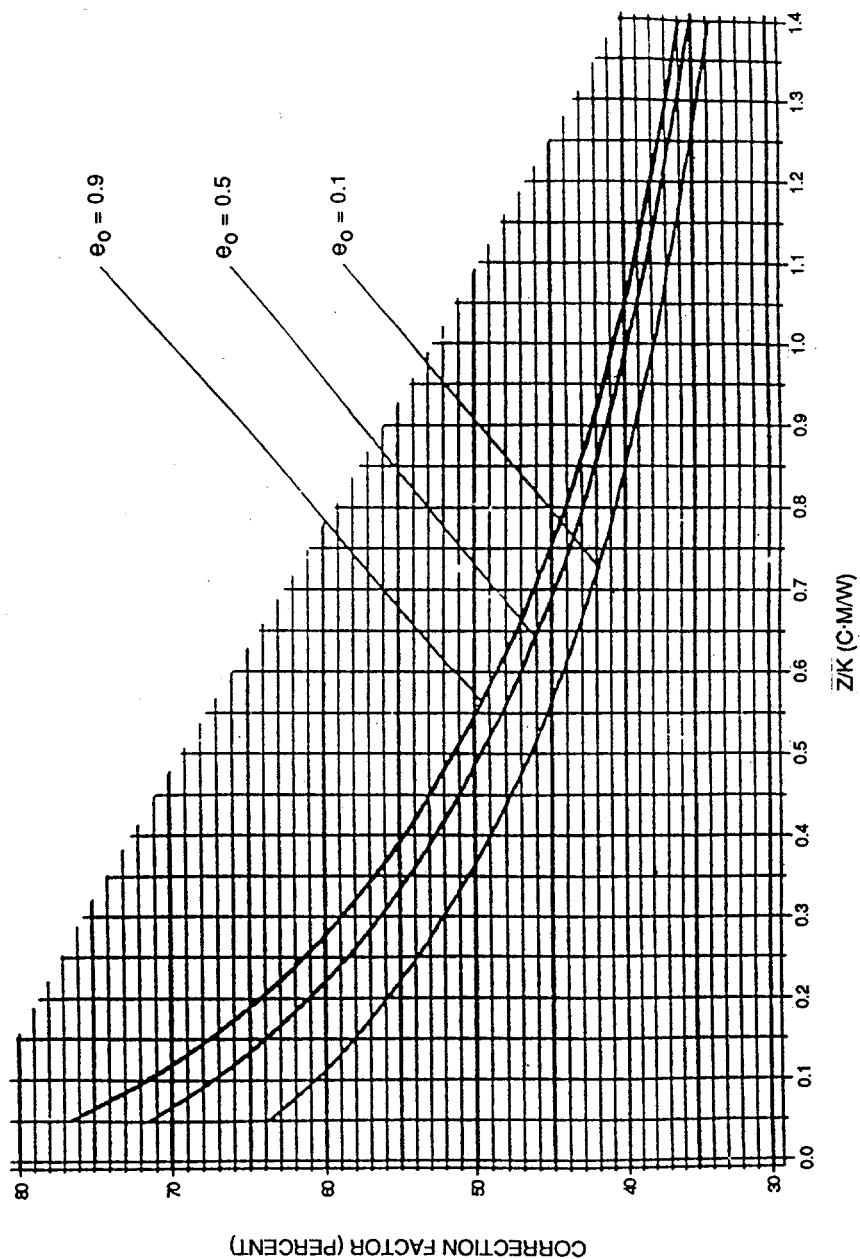


Figure 12-1 —Derating of Cables in Cable Trays Due to Fire Barriers (Percent Correction Factor to be Applied to ICEA Ampacity Tables)

12.3.8 Design Guides and Practices

The following are design guides and practices that can be employed.

The conductor size usually is established first by multiplying the rated or load current by a factor in the range of 1.15 to 1.25, then selecting a conductor rated to carry this larger current. When overcurrent protective device settings are determined, it is useful to compare the selected conductor ampacity with the protective device trip setting. Power cables may be sized to carry fault current for the time it takes the protection devices to function within the limit for total conductor temperature (in addition to the above requirements). In addition, cable conductors are sized to operate with acceptable voltage drop for full load and inrush current duty.

Both multiconductor and single-conductor control cables are sized to provide mechanical strength rather than ampacity. This results in a current carrying capacity of the conductors that is greater than the actual current requirement. These cables are typically #14 AWG to #10 AWG. The larger sizes are generally used to reduce resistance in long circuits or current transformer leads.

Instrument and thermocouple cable size is generally established by mechanical strength requirements. The conductor size is typically #16 AWG.

12.4 Nonsegregated Phase Bus

A nonsegregated phase bus is one in which all phase conductors are in a common metal enclosure without barriers between phases.

The nonsegregated phase bus system is used for connecting transformers to associated switchgear assemblies and for tie connection between the switchgear assemblies or between motor control centers. It is also used as the main generator bus in smaller power units. Normally, nonsegregated phase bus is used on circuits when the need for physical protection is greater than can be provided by cable in tray.

Nonsegregated phase bus is used commonly in ratings through 6000 A. Higher ratings are also available. The proper application of a bus structure requires a knowledge of the bus ratings and the service conditions under which the bus structure is to be used. With this knowledge, it is possible to select the proper bus structure for the requirements of the application in question.

Nonsegregated phase bus is available for indoor or outdoor application with removable gasketed covers. Ventilation or heating of the enclosures may or may not be required. In the gasketed enclosure design, each internal throat flange is insulated from adjacent sections. A continuous ground conductor should be installed in parallel with the bus enclosure, and each gasketed section should be grounded. The ground conductor should be connected to the station ground at one point only, although more connection points are satisfactory if induced current loops have been avoided. Induced voltage across insulated joints in the enclosure should be kept as low as possible, and preferably below 2 V, during rated current operation.

For high current installations, considerations should be given to the problem of induced magnetic heating and induced circulating current in nearby metallic members such as support beams, reinforcing rods, etc. Suitable insulated gaps in the steel work, to eliminate closed loops and amortisseur bands around steel members, will aid in solving the problem.

Nonsegregated phase bus may have sections located both inside and outside a building, so that ambient temperatures may be appreciably different at the same time. The bus should include sealing means or baffles, such as a wall plate with fire and vapor barriers, to prevent an interchange of air between sections. Furthermore, widely fluctuating ambient air temperatures for any one section of bus necessitates consideration of the resulting enclosure air temperature, condensation, and pressure change. Ventilation with filtered breathers can be provided. Filtered drains are also provided at the low point in vertical sections to prevent accumulation of condensation. Where bus duct penetrates fire barriers (fire rated walls and floors), the integrity of the fire barrier should be considered in the design of the bus duct system.

On bus rated 8000 A and above, consideration is given to forced-air cooling. On forced-air cooled buses, a smaller conductor can be used. This presents savings both in space and the purchase price of the bus. The resultant heat generated by increased losses is carried away by cooling air. An economic study can be made to compare the increase in losses versus the purchase price savings of using a smaller conductor. On high current buses, a forced-air cooled system can result in as much as 50% savings. However, there may be a significant reduction in availability due to dependence on blowers and heat exchangers.

12.4.1 Conductors and Enclosures

Copper and high conductivity aluminum alloy are the standard materials used for bus conductors. Using aluminum conductors may result in a lower purchasing price, plus savings in field handling costs. The conductors may be bars, channels, angles, extrusions, or round, square, or octagonal tubes, depending on electrical and mechanical bus ratings and the service conditions under which the bus is to be used. The conductors may be bare or insulated. Welded or bolted flexible connectors should be provided at terminations and along the length of the conductor. All bolted contact surfaces should be silver plated. Special sections of bus are available for expansion joints and removable disconnect links. Custom design sections can be provided for each application.

The bus supports may be polyester glass or porcelain insulators for standard ratings. Extra high strength insulators are available for special momentary ratings.

Enclosures should be of the totally enclosed type, formed of sheet aluminum or steel. They can be designed for use either indoors or outdoors, and should be weatherproof or dust tight. Due to the relatively high labor rates in construction, it is advantageous to assemble the three-phase sections in the factory prior to shipment. Aluminum enclosures may be used for 3000 A and higher to reduce inductive heating.

The enclosed bus assembly should be designed so that the maximum conductor temperature rise above an outside ambient temperature should not exceed the allowable hot spot temperature while continuously operating at rated full load capacity.

The rated voltage of a bus structure is the highest nominal system voltage at which it is designed to operate. Table 12.6 lists the standard voltage ratings for bus structures that might be used at power generating stations.

The rated continuous current of a bus structure is the current in amperes at the rated voltage and frequency that it will carry continuously without exceeding the maximum permissible temperature rise. Table 12.7 lists the standard current rating for bus structures at rated voltage.

The rated momentary current of a bus structure is the current that the bus structure will carry during short-circuit condition and still withstand the mechanical forces and the thermal effects associated with short-circuit rents. Table 12.8 lists standard momentary ratings for bus structures.

Table 12.6 — Standard Voltage Ratings for Bus Structures

Voltage Rating kV		Insulation Level kV	
Nominal Voltage	60 Hz Low Frequency Withstand	Impulse* Withstand	Dew Withstand 10s
0.6	2.2	—	—
4.16	19	60	15
6.9 and 13.8	36	95	24
14.4	50	110	30
23.0 [†]	60	150	40

*1.2 · 50 is positive or negative.

[†]When used as generator leads at voltages 14.4 kV to 24 kV, the 60 Hz and impulse tests may be specified as 50–110 kV respectively, where adequate surge protection is provided.

Table 12.7 — Standard Current Ratings for Bus Structures

Rated Voltage(kV)				
0.6	4.16	6.9 and 13.8	14.4	23
Amperes				
600	—	—	—	—
1200	1200	1200	1200	1200
1600	—	—	—	—
2000	2000	2000	2000	2000
—	—	—	2500	2500
3000	3000	3000	3000	3000
—	—	—	3500	3500
4000	—	—	4000	4000
—	—	—	4500	4500
5000	—	—	5000	5000
—	—	—	5500	5500
6000	—	—	6000	6000
			6500	6500
			7000	7000
			7500	7500
			8000	8000
			8500	8500
			9000	9000
			9500	9500
			10 000	10 000
			11 000	11 000
			12 000	12 000

NOTE — Higher current ratings are available by the addition of forced-air cooling.

Table 12.8 — Standard Momentary Current Ratings for Bus Structures

RMS Total Amperes				
Rated Voltage (kV)				
0.6*	4.16 [†]	6.9 and 13.8 [†]	14.4 [†]	23 [†]
2500	20 000	20 000	7700	7700
50 000	40 000	35 000	116 000	96 000
75 000	60 000	40 000	192 000	116 000
100 000	80 000	60 000	240 000	192 000
125 000	—	80 000	300 000	240 000
150 000	—	—	—	300 000

*To get symmetrical amperes, divide by 1.25.

[†]To get symmetrical amperes, divide by 1.6.

12.4.2 Temperature Limitations on Ambient Air

The normal, average, ambient temperature for air surrounding the metal-enclosed bus will be in the range of 40 °C to –30 °C. Where the ambient temperature is higher than 40 °C or lower than –30 °C, the application should be considered special.

For general information regarding the effect of solar radiation on outdoor metal-enclosed bus, see IEEE C37.24-1986 [25].

When bus structures are operated at altitudes above 3300 ft, the standard voltage and current ratings should be multiplied by the correction factors as shown in Table 12.9.

Table 12.9 — Correction Factors for Bus Ratings at Various Altitudes

Altitude in ft	Correction Factor for Voltage	Correction Factor for Current
3300	1.00	1.00
4000	0.98	0.996
5000	0.95	0.99
10 000	0.80	0.96

13. Physical and Environmental Aspects

13.1 Introduction

The physical location and arrangement selected for electric power service equipment within generating plants is effected by design of equipment, environment at the proposed location, protection from physical damage, and requirements for reliability and long life. Equipment containment enclosures, cooling systems, and maintenance procedures should be designed to accommodate the environment at the equipment location.

Electric power service systems are vital to the operation of the generating stations. However, their cost is a relatively small proportion of total investment. Therefore, additional cost for the best practices in equipment location and installation usually are justified to assure reliable service.

Physical configuration of electric power service systems for generating stations is significantly influenced by size and type of generating unit, cost of connections to the high-voltage switchyard, and transformer losses. Fugitive ash and coal dusts, cooling tower mists, and higher than normal ambient temperatures also are significant factors.

Physical aspects of electric generating stations and their electric power service systems are specifically effected by

- 1) Power system size and configuration
- 2) Generator prime mover size
- 3) Type of fuel and fuel source
- 4) Geographic location
- 5) Power system switchyard location, arrangement, and voltage
- 6) Regulatory criteria and safety codes
- 7) Owner criteria
- 8) Generating station heat sinks

Consideration should also be given to protecting components from environmental phenomenon such as floods, hurricanes, tornadoes, seismic events, and salt sprays.

Availability and reliability of a station and its individual units are improved when components are arranged and physically protected so as to minimize the failure of any one component, thereby causing failures to additional components.

This design guide describes the physical aspects of the electrical power equipment in relation to the environmental conditions that may effect the performance and reliability of the equipment. However, the mechanical solutions (HVAC, fire protection, acoustical, etc.) are beyond the scope of this section.

13.2 Service Transformers

The power supply (primary) connection of service transformers, for intermediate and low-voltage power service, and their physical location are dependent on the type, size, economics, and reliability requirements of the generating unit.

The number of the power transformers, their internal connections, voltages, and connections to the electrical system are described in Sections 5.–9. The main unit (step-up) transformer and unit and system auxiliaries transformers, being large sized and oil cooled, are usually outdoor mounted. From the physical and environmental standpoint, they are treated very much alike.

13.2.1 Unit Auxiliaries Transformers

Power to unit auxiliaries may be supplied at generator or switchyard voltage. Unit auxiliaries transformers connected to the generator bus are an added cost (because station service transformers are required for startup unless a generator breaker is furnished), but they are more reliable, result in lower total losses for the auxiliary system, and give smaller auxiliaries system voltage excursions during operation than station service transformers. They are also unaffected, to a large extent, by disturbances at the switchyard.

The cost of generator buses and bus losses makes it desirable to keep buses and their taps as short as possible. Therefore, generator step-up and unit auxiliaries transformers are located close to the generator, quite often just outside of the turbine building.

These transformers usually contain large amounts of combustible cooling oil. It is essential that they be separated effectively from the building and other equipment by fire walls or space. All fire wall penetrations must have a fire withstand rating that meets the minimum fire withstand requirements of industry standards.

Provisions also must be made for extinguishing oil fires and for collecting and draining spilled oil. A rock filled basin usually is provided to cool the oil below its ignition temperature before it enters the drain system. The drain system may require an interceptor type manhole. The capacity of the deluge system or other suppression system should also be considered when designing the drain system to meet environmental standards.

13.2.2 Station Service (Startup) Transformers

When auxiliaries transformers for a generating unit are connected to the generator bus, a station service transformer, supplied from the transmission switchyard, usually is required to start the unit and to supply unit auxiliaries when the generator is not operating. Where a generator breaker or generator disconnect device is used, the unit auxiliary transformer can serve as the station service (startup) transformer.

The station service transformer typically will be filled with combustible oil and will require the same considerations for fire protection as the unit auxiliaries and unit transformers.

13.2.3 Unit Substation (Load Center) Transformers

Unit auxiliaries-system unit substations provide power service at low voltages. They usually are supplied from the medium-voltage switchgear and usually consist of a transformer and the low-voltage switchgear (600 V and lower) to feed smaller auxiliaries and motor control centers. The location and number of these load centers is determined by the load they are to supply. The load centers very often supply motor control centers located near the load to reduce voltage drop and cost of cabling. The substation transformer and the load center usually are one unit within a common enclosure. The preferred solution is to locate them within an enclosed room that can also contain circuit breaker panels. Experience has demonstrated that it is detrimental to the electrical equipment for it to be installed in the same room with the mechanical equipment, i.e., boiler room, bunkers, or the lower level of the turbine building. Therefore, such placement should be discouraged. However, if there are strong economic reasons for locating the transformer and load center freestanding in the boiler or turbine house, they should be purchased with suitable enclosures and ventilation or cooling systems. Unit substation transformers located within the powerhouse should be air-cooled, gas-filled, cast-coil, or filled with nonflammable cooling fluids.

In some designs, the substation transformer may be installed outdoors. In this case, it may be oil-filled and may require a fire protection system.

13.2.4 Lighting Transformers

Lighting transformers are located preferably near the area to be lighted in order to reduce the cost of wiring and voltage regulation. The number and size of the lighting transformers is determined by the extent of the lighting system. They seldom require maintenance; therefore, any economical enclosure and location may be selected. They usually are dry-

type transformers located near the lighting distribution panel, and they should have good accessibility. They may be mounted on walls, in motor control centers, or may be freestanding. Rooms designed for unit substations and medium-voltage switchgear are good locations for lighting transformers.

13.3 Switchgear

13.3.1 Medium-Voltage Switchgear (Greater Than 600 V)

The most economical location for electric-power distribution switchgear is near its load because this reduces the cost of feeder circuits supplied by the switchgear. However, when large-capacity switchgear units require alternate supplies (from startup and unit auxiliaries transformers), there may not be a significant gain because the length and cost of supply cable may equal that of the load feeders.

The medium-voltage switchgear requires a large amount of floor space. While sizing the floor surface extra space is required, in addition to the surface occupied by the switchgear, for equipment access during normal operation and maintenance activity such as the removal of main equipment, cable, wireway, etc. Sufficient space should be provided in front of the switchgear for convenient withdrawal of the circuit breakers. For safety reasons, access should be provided from both ends of the switchgear to allow for the possibility, if a person is caught by a short-circuit accident, of escape from any point around the switchgear.

When located within the power plant, a switchgear often requires special cooling. Therefore, it is often installed within its own clean, drip-proof (from above), ventilated room, accessible only to authorized personnel. Smoke detection alarm systems are recommended in switchgear rooms. The room is locked usually to prevent unauthorized access, and the doors should be provided with crash bars to allow easy exit for safety reasons. Air used for ventilation is drawn usually from a clean source in sufficient volume to pressurize the room and prevent infiltration of dust and other contaminants that would have an adverse effect on the electrical equipment. Equipment located in high ambient temperature locations may require a cooling system. Equipment heat loss data is available from the manufacturer.

Power plant enclosure ambient temperatures, in some cases, may be 50 to 60 °C, unless they are controlled by forced ventilation. In these situations, switchgear that is designed to operate at 40 °C ambient should be derated or forced-cooled to reduce the operating temperature.

Medium-voltage switchgear is mounted normally on steel channels because of the heavy weight and large impacts transmitted to its base by fast acting circuit breakers. The channels must be level and embedded in the concrete floor. Manufacturers' recommendations for channel and floor leveling should be followed to assure alignment and proper operation. Manufacturers will supply the correct channels for their switchgear, or channels can be bought separately with drilling to match the switchgear.

Connections between switchgear groups, to carry an incoming supply to another group, are accomplished typically with cable bus or bus.

13.3.2 Load Centers (Unit Substations) (600 V or Less)

A load center or unit substation is a coordinated assembly of a three-phase transformer with a medium-voltage incoming line section, a transition section, and a low-voltage switchgear section. Unit substations may be of indoor or outdoor design with open ventilated, gas-filled, or cast-coil transformers.

A location close to the area of load concentration for the load center is preferred. The environment of that area will determine the type of transformer and enclosures required. A ventilated and pressurized room typically is provided for the use of a ventilated, dry-type transformer and standard enclosure. An open area in the boiler house may require a gas-filled or cast-coil transformer with a NEMA 12 indoor, dust tight enclosure for the low-voltage switchgear. When an outdoor location is selected, options include either sealed dry, gas-filled, or oil-filled type transformers. If an oil-

filled transformer is considered, then the possibility of oil leakage should be accommodated for with either a dike around the transformer or an interceptor manhole to hold the oil.

The load center with low-voltage switchgear may be installed in the medium-voltage switchgear room or near the center of the load. The medium-voltage switchgear room may be remote from the load but could provide a controlled environment. The increased cost and voltage regulation (because of additional cable) may be acceptable if reliability is improved and maintenance costs are reduced. However, concentrating all switchgear in one room tends to increase the probability of failures from a single accident, i.e., common event failure. Cable entry into the low-voltage switchgear may be from the bottom or top, as long as the room design does not expose the top of the switchgear to liquids. In this case, top entry sealing will be required.

The load center with low-voltage switchgear is furnished with built-in channels and can be mounted directly on a concrete floor, if the finish is adequately smooth and level. Care must be taken to see that the channels are level over their entire length to ensure that doors and mechanical interlocks properly align.

In-plant location of the load center with low-voltage switchgear near the physical center of the load served will reduce installation cost and improve efficiency and voltage regulation. However, maintenance costs may be higher and reliability may be lower unless environmental conditions are controlled. Equipment should be located where no overhead water sources are present, unless the switchgear is adequately protected to minimize water damage. Consideration should be given to higher-quality enclosures when equipment is located in-plant in locations where environmental conditions are undesirable. See 13.8 for enclosures.

Outdoor location of the load center will require the low-voltage switchgear section to have a weatherproof enclosure of either the walk-in or nonwalk-in design. Space heaters will be required to control moisture.

13.3.3 Motor Control Centers

Motor control centers may also contain lighting transformers, panels, and circuit breakers to feed to other panels and loads. These panels should be located near the center of the load served to reduce cable lengths, give better voltage regulation, and lower installation cost. In addition, they should be located as to preclude being effected by possible pipe leaks and other sources of water.

Motor control centers are assembled at the factory on smooth and level surfaces to assure correct alignment of all parts. The foundation in the plant should be true and level, or the bottom frames must be shimmed to support the entire base in a true plane. An uneven foundation can cause misalignment of the shipping sections, units, and doors. Leveled channel sills under both the front and rear of the control-center base should be used to provide this base.

13.3.4 Panelboards

Circuit breaker panelboards usually are used for providing lighting, low-voltage power distribution, and dc power distribution.

13.3.4.1 Location

The panelboards generally are wall mounted, although power distribution panelboards may be large enough to be floor-mounted.

Panelboards should be located at convenient locations near the loads they supply. The environment of the location must be considered, and NEMA enclosures, as described in 13.8.1, should be used.

13.3.4.2 Lighting Panels and Power Centers

Lighting power centers are often similar to the low-voltage switchgear, that is, a transformer and switchboard designed as a unit. The preferred location would be in the ventilated room of the medium-voltage switchgear, although a location in the plant could be used, taking into account the same considerations as with low-voltage switchgear.

In some plants, much of the lighting is supplied from motor control centers with lighting transformers and panels installed inside them.

Lighting panel boards should be located and mounted on a wall or column such that their circuits do not run more than 100 ft to the first outlet. A minimum of 20% spare circuits should be allowed, and space should be provided for these spares in the wireways.

13.4 Space, Growth, and Cable Entry

13.4.1 Space

Medium-voltage and low-voltage switchgear require ample space for installation, maintenance, testing, operation, and growth. Both require space to connect feeder cables and to withdraw the units. A minimum of 5 ft at the front and at the ends or sides, and 3 ft at the rear, should be provided for switchgear. Manufacturer's information should be consulted for actual dimensions that vary based on manufacturer's design, voltage level, and interrupting capacity.

Motor control centers can be designed to be placed against a wall or to be placed with sufficient space from the wall to allow free access to rear panels. The front of the motor control center should have sufficient working area when the doors are open.

Single front motor control centers can be mounted against the wall. Back-to-back units can be mounted 36 in from the wall; however, more space is desirable.

13.4.2 Growth

Location and arrangement of equipment should provide for future additions. Spare low-voltage switchgear load feeder circuits should be provided to utilize the full capacity, including diversity of the power supply. In motor control centers, combination starter panels should have several blank spaces with doors for size 1, 2, and 3 combination starters and feeder breakers, or they should be provided with spare combination starters and feeder breakers. Circuit breaker panelboards should have at least 20% spare capacity.

While designing the equipment location, the equipment room should be sized, considering the direction of expansion for the switchgear or motor control center without diminishing safe personnel access.

13.4.3 Cable Entry

Cable entry to switchgear and panels normally should be from the bottom, when practical, to prevent the inadvertent entry of water. In protected locations, such as switchgear rooms, when bottom entry is not feasible, top entry is acceptable if the area is well protected. Top cable entry should be designed and sealed to prevent water entrance. Particular attention should be given to plant areas in which piping in the boiler house and lower turbine building are present.

The arrangement of the feeders within the switchgear should be in agreement with the location of the load in order to avoid overloading cable trays with cables crossing and going in opposite directions.

13.5 Ambient Temperature

The useful life of solid electrical insulation is inversely proportional to the temperature of the cooling medium (usually ambient air) plus the temperature rise of the insulated conductor. Standard equipment ratings are dependent on standard ambient temperature. However, a generating station has a wide variation in ambient temperature except in those areas in which it is controlled by air heating and cooling equipment.

IEEE Std 1-1986 [B7]³¹ specifies limiting ambient temperature as follows:

- 1) For self-ventilated (self-cooled) equipment, the ambient temperature is the average temperature of the air in the immediate neighborhood of the equipment.
- 2) For self-ventilated equipment operated in an enclosure as a complete unit, the ambient temperature is the average temperature of the air outside the enclosure in the immediate neighborhood of the equipment.
- 3) For equipment with a heat exchanger that is not integral with the equipment, the ambient temperature is that of the ingoing cooling medium to the equipment.
- 4) For equipment completely buried in the earth, the ambient temperature is the temperature of the earth near the equipment but sufficiently remote so as not to be affected by the heat dissipated. It also is the temperature of the earth adjacent to the equipment when the equipment is not contributing heat to the surrounding medium.

13.5.1 Equipment Ratings

Major equipment ratings are based on the ambient temperatures in Table 13-1. When ambient temperatures exceed the standard values, the equipment should be derated, relocated, or provided with an enclosure having controlled air conditioning or ventilation. Other choices are also available. Equipment may be water-cooled or ventilated with ducted air from a cooler or air-conditioned source. The alternative selected is dependent on cost and desired reliability. When additional enclosures, fans, and air conditioning equipment are used, the reliability may be reduced.

Table 13.1 — Major Equipment Ratings Based on Limiting Ambient Temperature

Equipment	Limiting Ambient Temperature for Rating Equipment
Motors	40 °C
Switchgear	40 °C
Wire and Cable	
Air cooled	40 °C
Duct banks	20 °C (earth)
Transformers	
Liquid filled—Air cooled	30 °C*
Water cooled	25 °C
Dry type	30 °C*
Batteries	25 °C
Battery Chargers	50 °C
Uninterruptible Power Supplies, Air Cooled	25 °C
Inverters, Converters	
Air cooled	40 °C
Water cooled	25 °C†

*24 h average and the maximum temperature not to exceed 40 °C for an 8 h period.

†24 h average and the maximum temperature not to exceed 30 °C for an 8 h period.

³¹The numbers in brackets, when preceded by the letter “B,” correspond to the Bibliography in 13.13.

13.6 Elevation

The heat transfer capability of air is significantly reduced by reduction in its density as elevation above sea level is increased. The elevation above sea level for the installation should be specified in the procurement documents. This informs designers that additional heat transfer surface and additional air volumes are required to achieve standard ratings. Also, clearance between live parts and to ground may be effected.

Most equipment, however, is designed to permit installation up to 1000 m (3300 ft) above sea level without derating (see IEEE Std 1-1986 [B7]).

13.7 Expected Life and Reliability

Failures of electrical equipment may be classified as thermal, mechanical, chemical, and common mode. Expected life and reliability are related to the capability of the equipment to withstand the environmental conditions and stresses to which it may be subjected, which will include temperature and humidity stresses induced through expansion, contraction, and vibration exposure, where applicable. Common-event failures (common mode failures) occur when more than one electrical system component fails due to a single event such as fire, seismic shock, flooding, high bus voltage, low bus voltage, high bus frequency, low bus frequency, fault current, etc.

13.7.1 Mechanical Failures

Mechanical failures in electrical equipment (medium-voltage switchgear load centers, etc.) are caused by manufacturing and assembly errors, misalignment and assembly errors during installation and maintenance, lack of maintenance, excessive number of operations, excessive vibration, and excessive fault current. These failures will be random, and their probability is reduced by quality control, periodic inspection, and functional testing.

Mechanical failures may also be caused by overstressing materials (beyond the yield point) during overvoltage and short-circuit conditions, as well as excessive temperature differentials. Repeated overstressing may result in fatigue failures.

13.7.2 Chemical Failures

Chemical failures occur when corrosive atmospheres and electrolytic corrosion cause increased resistance of electrical contacts or destroy equipment enclosures. Some corrosive atmospheres may also cause rapid deterioration of electrical insulations. These failures are random, and their probability is reduced by selecting compatible materials, enclosures, and adequate ventilation, and maintaining the equipment temperature above the dew point.

Aluminum-to-copper connections should have both mating surfaces electroplated with silver or tin to reduce electrolytic corrosion. A copper/ aluminum pad between the lug and bus is advisable. If the connections are dry at all times (i.e., no electrolyte), the probability of electrolytic corrosion is very small. Aluminum should always be above copper outdoors to minimize corrosion.

Protective coatings for conductors (bolted connections) could be tin or silver. Gold and platinum may be used on small contacts. Protective enclosures may be made entirely of stainless steel, aluminum, fiberglass, or polymer compounds. The material selected will depend upon the corrosive atmosphere and the acceptable costs.

13.7.3 Common Event Failures (Common Mode Failures)

Common-event failures are significant in situations in which they can cause loss of electric power service to essential auxiliaries. This can cause loss of the entire generating unit or generating station. They can also endanger personnel and cause extensive damage to power plant equipment.

Common event failures may be caused by catastrophic natural events such as seismic events, hurricanes, tornadoes, lightning, flooding, etc. They may also be caused by events within the power plant such as pipe rupture, fire, initiation of fire protection systems, excessive power system voltage, control-battery failure, etc.

When a function, such as lubrication or cooling, is essential to personnel safety or prevention of extensive equipment damage, it should be performed separately and independently by two or more auxiliaries that have independent power and control supplies, circuits, and cabling.

The separate and independent power supplies should be physically separated with suitable barriers or distance to prevent common event failures. Their structures and enclosures must be designed to withstand seismic shock waves, fires, hurricanes, and similar events as well.

13.8 Enclosures

Enclosures for electrical circuit components protect the components from the environment, protect the population from electric shock, and contain the cooling medium to prevent fires and explosions. The enclosures may be buildings, rooms, vaults and fences, or housings (frames), cabinets, boxes, and tanks.

A single enclosure may provide any or all of the requirements. Selection will depend on the electrical component, its location, and acceptable costs.

The generating station design will effect the environment of areas within the plant. A coal-fired boiler design will be clean compared to one with a pressurized boiler design. The geographical location of the station, with respect to climate and indoor/outdoor design, will again determine the environment in which electrical equipment must operate. Once the environment of the equipment location is determined, the required type of NEMA enclosure can be established.

Removal of heat generated within the enclosure may require ventilation, an increase in enclosure dimensions, or cooling radiators.

13.8.1 NEMA Enclosures

Enclosure standards have been developed by the National Electrical Manufacturers Association (NEMA) (see [B12]). NEMA standards identify the functional requirements of each type of enclosure.

Standard NEMA 1 enclosures can be used in protected areas that are clean and dry and not subject to washdown. Normal enclosures for power plant use should be NEMA 12 with drip shields, if needed. In some cases, outdoor enclosures should be considered. Where the possibility of dripping water exists, equipment can be provided with a pan-type drip shield. In washdown areas, NEMA 4 enclosures should be specified.

13.8.2 Hazardous (Classified) Locations

A hazardous location is any area in which continuous or accidental release of flammable gases vapors, dusts, fibers, or filings into the air could result in an explosion or fire. Enclosures for electrical equipment in hazardous locations should operate below the ignition temperature and be capable of containing all sparks. Explosions within the enclosures should be completely contained, or the gases should be cooled before being released in to the surrounding atmosphere.

Hazardous locations have been classified by the National Fire Protection Association (NFPA). They are included in NFPA 70-1990 [B15] and ANSI C2-1990 [B1]. NEMA ICS 6-1988 [B12] defines enclosures suitable for these classifications.

Hazardous materials are classified as liquid and gaseous (Class I), dust (Class II), or fibers (Class III).

Areas (locations) are classified as those locations where hazardous materials may be present during normal operation (Division 1), or locations where hazardous materials are present following a leak or ventilation and containment failure (Division 2).

Hazardous materials are also grouped as to their ignition temperature and conductivity. Class I materials are grouped by ignition temperature groups *A*, *B*, *C* and *D*. Class II material, are grouped as ignition and conductivity groups *E*, *F*, and *G*. See Table 13.2.

13.8.3 Division 2 Locations

13.8.3.1 Coal-Handling Locations

The coal-handling areas are considered to be hazardous locations, as follows:

- 1) *Class II*. Combustible and/or conductive dust.
- 2) *Division 1*. The hazard is present during normal operating conditions.
- 3) *Group G*. Combustible dust with a resistivity of $10^5 \Omega/\text{cm}$ or greater. (This is considered to be nonconductive resistivity.)

Electrical equipment that is qualified for use in hazardous areas usually meets the requirements for several categories. These can include Class I for flammable gas or vapors (explosion-proof) as well as Class II (dust-ignition proof). It should be noted, however, that explosion-proof equipment does not always meet the requirements for Class II hazards. Therefore, careful attention must be given when selecting material for use in Class II hazardous areas. The Class II, Division 1, and Group G categories must be included among the listings for all electrical equipment used in the coal-handling areas. Catalog information specifies the classifications as they pertain to each item. Any equipment that does not specify a particular Division is approved for both Division 1 and Division 2 installations. The NEMA designation for Class II boxes/enclosures is NEMA 9.

Table 13.2 — Hazardous Material ClassesClass I (Liquids and Gases)Lowest Ignition Temperature

<u>Group</u>	<u>°C</u>	<u>°F</u>
A	280	536
B	280	536
C	180	356
D	280	536

A — acetylene

B — hydrogen

C — ethylene

D — gasoline (or alcohol)

Class II (Dusts)Maximum Surface Temperature

<u>Group</u>	<u>Not Subject to Overload</u>		<u>Possible overload</u>			
	<u>°C</u>	<u>°F</u>	<u>Normal</u>		<u>Abnormal</u>	
	<u>°C</u>	<u>°F</u>	<u>°C</u>	<u>°F</u>	<u>°C</u>	<u>°F</u>
E	200	392	200	392	200	392
F	200	392	150	302	200	392
G	165	329	120	248	165	329

Class III (Fibers)Maximum Surface Temperatures

Not Subject to Overload — 165 °C, 329 °F

Possible Overload — 120 °C, 248 °F

Equipment in Division 2 locations may become covered with coal dust due to malfunction of coal handling enclosures. All electrical enclosures should be limited to a normal surface temperature of 150 °C, with maximum deviations to 200 °C, to prevent ignition of dormant coal dust.

During accident conditions, the atmosphere may contain explosive quantities of coal dust. Therefore, all electrical equipment that could cause an arc should be in NEMA 9 enclosures. Motors should be totally enclosed to prevent coal dust accumulation in the motor rotor windings where temperatures could exceed 200 C. Totally enclosed, tube-cooled motors also meet this requirement. All contactors, limit and control switches, circuit breakers, and lighting in these locations must be in NEMA 9 enclosures.

13.8.3.2 Oil Handling and Storage Location

Nonvolatile oils used for lubrication, transformer cooling, and boiler and diesel fuel whose flash point in above 138 C are classified as nonhazardous. In nonventilated oil-handling locations, or where leaking oil or vapors could accumulate on electrical equipment, oil-tight ignition-proof enclosures should be used.

In locations where accidental leaks could cause oil sprays or explosive oil vapors, all contactors, limit and control switches, and lights should be in oil-tight, ignition-proof enclosures.

13.8.4 Station Battery System

A storage battery system includes the station battery, a battery charger, and a dc distribution panelboard, and provides essential dc control power for the unit, as well as emergency power supply for station inverters, lighting, hydrogen seal oil pumps, and emergency bearing oil pumps in the event of loss of ac supplies to the unit. Location of the battery should be in a separate protective enclosure, which may be a battery room, control building, or fence, to minimize the possibility of inadvertent contact with energized parts.

The protective enclosure should provide space for safe inspection, maintenance, testing, and cell replacement. Space should be left above the cells to allow for operation of lifting equipment, adding water, and taking measurements.

The protective enclosure should be ventilated, if enclosed, by either natural or powered ventilation to prevent accumulation of hydrogen and to maintain the desired ambient temperature. The ventilation system should limit the accumulation to less than an explosive mixture.

The floor of the battery location should be made of acid resistive material or painted with acid resistive paint. Battery racks should be anchored firmly to the floor. If metal, the cell jars should be installed on plastic strips and spacers such that they are not in direct contact with the metal racks. Cell surfaces should be cleaned routinely to eliminate electrolyte forming a low resistance path to the metal rack. Refer to IEEE Std 484-1987 [B10] for additional details on battery installation design.

13.8.5 Hydrogen and Welding Gas Storage

These are Class I, Group *B* materials. If enclosed storage areas are used, all electrical equipment in the enclosure should be explosionproof. This is not required if storage is in large, well ventilated structures.

13.8.6 Ash-Handling Locations

Fine ash collected from flue gases (fly ash) and slag collected from the furnace walls (bottom ash) may be corrosive when wet and are always erosive.

When pressurized air is used to transport fly ash, accidental leaks will result in accumulations of fly ash on electrical equipment. Accidental spillage of fly ash also occurs when maintaining ash handling systems. Therefore, all electrical equipment in these locations should be enclosed in dust-tight, NEMA 12 enclosures.

Water is used to transport bottom ash. Because of the corrosive and erosive nature of the material, accidental leaks and spills during maintenance are frequent. All electrical equipment should be in dripproof, dusttight enclosures, and there should be protection against corrosion. Aluminum conduit and enclosures should not be used, unless of a suitable alloy for the intended service. Corrosion resisting paint is recommended for all surfaces in these locations.

13.9 Indoor vs. Outdoor

Climate and cost are the determining factors in selecting indoor or outdoor locations for service equipment. Cost of outdoor enclosures vs. indoor enclosures and their relative location with respect to the loads to be served must be considered. Outdoor, and some indoor, equipment need space heating to prevent condensation due to day/night breathing. Maintenance of outdoor equipment during inclement weather may be a significant cost. When locating equipment outdoors, sun loading may raise the temperature of the electrical equipment enclosure, thus requiring derating, sun shields, or additional cooling.

13.10 Flooding

Areas subject to flooding should not be considered for location of electrical equipment. If such areas must be used, equipment should be installed on foundations high enough to prevent water entry into the bottom of the equipment. However, watertight, submersible equipment (NEMA 6) is available and can be used when flooding is highly probable or a normal occurrence.

Any conduit or other entrance into equipment located below flood level (but in an area protected by flood gates, barriers, etc.) should be sealed to withstand the expected static pressure.

13.11 Noise

There has been an increase in noise emissions from generating stations commensurate with the use of larger machinery. There has also been an increase in public concern to protect the working environment and prevent community nuisance due to generating station noise. Legislation requiring assessment and control of noise has been enacted at all governmental levels. Generating station noise control is expensive. Though there is more maneuverability in planning for noise control in the design stage, noise control features have to be consistent with the overall design of the station. Overall design includes the general arrangement of the equipment. There are other acoustical considerations, such as adequate noise specification for the equipment and checking compliance and estimation of the overall noise level set by the different equipment in the complex generating station environment.

13.11.1 Planning

Fundamental concerns in planning for noise control in generating stations are sound levels in the nearby community, in-plant personnel exposure, and speech interference levels.

The sound transmitted to the surrounding community from a generating station depends on location and orientation with respect to the community and the medium between the plant and the community. A large body of water allows sound to be conducted farther. The potential levels inside and outside also depend on

- 1) Whether the station uses fossil or nuclear fuel
- 2) Whether it is open or partially or completely enclosed
- 3) The arrangement of the equipment
- 4) Sound power of the equipment and its directivity
- 5) PA systems and speaker location in outdoor areas
- 6) Architectural features and acoustical treatments

Sound transmission loss required for walls of the control room and other offices depends on the level outside these areas and the interior noise control criteria.

Using a preliminary station layout, a generalized noise control model may be constructed as a design aid. Inputs for such a model will include the following:

- 1) Sound radiation from the equipment. The data on sound radiation from the equipment may be obtained from manufacturers or measurements on similar installations.
- 2) Spatial constraints/flexibility of the general arrangement.
- 3) Possibility of using noise control measures such as mufflers, enclosures, design, and supplier options.
- 4) Absorption on interior surfaces and transmission loss of plant construction.
- 5) Noise exposure in an 8 h shift of station maintenance and operating personnel during normal operation; OSHA requirements for personnel noise exposure.
- 6) General orientation of the station.
- 7) Community noise requirements.
- 8) Water cooling system.

- 9) Topography of the plant site.
- 10) Economic considerations, including
 - a) Additional cost of buying low noise machinery
 - b) Administrative controls
 - c) Economic feasibility of acquiring enough land surrounding the station site, if needed, for required noise attenuation

13.12 Fire Protection

Major fire hazards found in a fossil fueled generating station are unenclosed fire hazard areas, flammable liquid storage and use, coal storage and handling, transformers, and cooling towers. Various design and equipment needs can add to the list. Examples include dust collectors, hydrogen storage, pulverizers, cable runs, cable spreading areas, control rooms and consoles, and general storage areas.

13.12.1 Unprotected Areas

Fire protection design criteria cannot revise the required functional features of the power generating station. However, much can be done by the design engineer to protect the modern plant.

13.12.2 Flammable Liquid Hazard

Protection of oil storage tanks and oil reservoirs must be approached from a total concept standpoint. Automatic sprinkler or spray protection usually is the first consideration and, in most cases, will satisfy insurance recommendations. A diked area that can contain a complete rupture of the storage container should be avoided. Another method for an outdoor transformer location could be an interceptor manhole of sufficient size to contain the oil capacity of the transformer and the deluge system or other suppression system(s), as appropriate.

13.12.3 Control Rooms and Consoles

Control rooms, relay rooms, and consoles are best protected by dry agent storage systems. CO₂ is the common fire protection agent. It can be contained in individual cylinders, or it can be part of a plant system with a refrigerated storage system. However, Halon systems are preferred to CO₂ systems because of better performance.

A large, refrigerated storage system may be used to supply CO₂ to multiple protection systems, and it can supply hand nozzles in the pulverizer coal mill area.

13.12.4 Coal Handling Areas

The coal handling storage areas are not classified as an extra hazard area; but, from the standpoint of importance to plant operation, they are more of a hazard than flammable liquid storage and handling.

13.12.4.1 Storage Areas

The spontaneous heating of bituminous coal can present storage problems, especially freshly mined coal that absorbs oxygen quite rapidly. Hot spots develop when a spontaneously heated pocket of coal is not detected until it has been deposited in a coal bunker.

13.12.4.2 Conveyors

A carefully designed open-bead fixed-water system, located to discharge water over and under the conveyor belts and related equipment, is one certain method of total protection of the conveyor system. A temperature rate-of-rise detection system, installed at the peak or center of the conveyor enclosure is one method frequently used to initiate protection systems. Any rise in temperature of more than 8 °C per minute anywhere along the conveyor enclosure

should activate the detection system, open the water control valve, and discharge water through open nozzles in that section of the conveyor system. At the same time, it should sound a fire alarm and shut down the conveyor. The piping normally is empty and, therefore, is not subject to freezing in cold climates. If the deluge system water supply is shut off for any reason, the detection system still will perform as a fire alarm.

Accumulations of coal dust on oil lubricated machinery present sufficient fuel and ignition sources that may justify automatic sprinkler protection in the crusher house and tripper floor areas. These sprinklers can be standard wet or dry pipe systems, and they should be hydraulically designed to guarantee sufficient water supply and pressure to all of the sprinkler heads.

13.12.5 Transformer Areas

An electrical arc inside a transformer can vaporize the transformer oil causing a pressure build-up that can rupture the transformer case, thus spraying and igniting the oil. Radiant heat can buckle the structural steel surrounding the burning transformers, and the gravel diked area can become a sea flame.

The primary concern is not the involved transformer (already badly damaged), but, rather, the loss or damage to adjacent transformers, structures, and equipment from the tremendous heat. Usually, this condition will prevent a close approach for effective hose activity.

A water-fog or deluge water spray system correctly applied and distributed over all the vulnerable areas of the transformer will not only cool burning oil below its ignition temperature, but will keep adjacent transformers and structures cool enough to prevent heat damage.

A detection system installed around and over the transformers will detect the fire condition and activate the water control deluge valve. The nozzles, which are not effected by heat or smoke, are selected for their specific discharge pattern to avoid dry spots. Some high capacity nozzles have been developed to satisfy complete coverage and density requirements, and they can be installed at a greater distance from the transformer. They use a simplified piping arrangement, which permits maintenance and even complete removal of the transformer without disturbing the fire protection system.

13.12.6 Steam Turbine Generators

The most severe and frequent fires involving steam turbine generator units occur when the lubrication, control oil, or seal oil, with an auto-ignition temperature as low as 260 °C, comes in contact with a hot surface on the steam turbine, valves, or steam lines where the temperature can run as high as 566 °C.

In addition, the turbine generator unit cannot be stopped quickly when a fire occurs. The oil supply cannot be shut off until the unit stops rotating, which creates a tremendously complex extinguishing situation where run down time (cessation of motion) may be 30 to 45 min.

Fixed CO₂ or dry chemical systems can be used to protect these units, but the rundown time involving reignition of the pressurized lube oil system, and the relatively limited supply of dry agent as compared with the unlimited supply of water, are clear indications of the limitations of these alternatives.

13.12.7 Cooling Towers

Cooling tower fire protection does not fall into the category of ordinary construction protection and cannot be satisfied with a standard sprinkler layout just to fulfill an insurance requirement. This only holds true for the cross flow design tower. The counter flow tower design does land itself to a conventional automatic sprinkler layout.

The references at the end of this chapter lists additional information for cooling tower fire protection.

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