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	Engineering and Design HYDROELECTRIC POWER PLANTS ELECTRICAL DESIGN	
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US Army Corps
of Engineers

ENGINEERING AND DESIGN

Hydroelectric Power Plants Electrical Design

ENGINEER MANUAL

DEPARTMENT OF THE ARMY
U.S. Army Corps of Engineers
Washington, DC 20314-1000

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Manual
No. 1110-2-3006

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Engineering and Design
HYDROELECTRIC POWER PLANTS
ELECTRICAL DESIGN

1. Purpose. This manual provides guidance and assistance to design engineers in the development of electrical designs for new hydroelectric power plants.

2. Applicability. This manual is applicable to all civil works activities having responsibilities for the design of hydroelectric power plants.

FOR THE COMMANDER:

WILLIAM D. BROWN
Colonel, Corps of Engineers
Chief of Staff

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Table of Contents

Chapter 1
Introduction

1-1. Purpose

This manual provides guidance and assistance to design engineers in the development of electrical designs for new hydroelectric power plants. The manual should be used when preparing electrical designs for hydroelectric power plants for civil works facilities built, owned, or operated by the Corps of Engineers. Treatment of electrical systems for pumped storage plants is not covered in the manual, although much of the information is applicable to pumped storage plant systems and subsystems.

1-2. Applicability

This manual is applicable to all civil works activities having responsibilities for the design of hydroelectric power plants.

1-3. References

Required and related publications are listed in Appendix A.

1-4. Scope

a. Generator rating. The manual presents good engineering practice in designing electrical systems for hydroelectric power plants employing generating units of up to approximately 300 *MW* in rating.

b. Plant features. The manual deals with the electrical features of hydroelectric power plants, and covers the generating equipment, station service, various switchyard and transmission line arrangements, details of lighting, communication and control, and protective devices for plant equipment and related auxiliaries. Generators and power transformers are treated under their respective headings, but other equipment, materials, and devices are discussed under the distinct functional systems in which they are used.

c. Specification preparation. Information is presented to facilitate the preparation of specifications for major items of equipment using pertinent approved guide specifications, and specifications for suggested plant design features which take into consideration the numerous ancillary and control details that are required to carry out the intended plant function. Where alternate designs of functional systems are discussed, a preferred design is indicated to secure a degree of uniformity in plants of similar size and character. These preferred designs should be followed unless unusual conditions make them unsuitable or unreasonably expensive.

1-5. Codes

Portions of the codes, standards, or requirements published by the associations or agencies listed below are applicable to the work. A complete listing of codes, standards, and guides is contained in Appendix A, "References."

Institute of Electrical and Electronics Engineers (IEEE)

American National Standards Institute (ANSI)

Electric Power Research Institute (EPRI)

Illuminating Engineering Society (IES)

National Electrical Manufacturers Association (NEMA)

National Fire Protection Association (NFPA)

Underwriters Laboratory (UL)

1-6. Criteria

a. Preferred methods. The design methods, assumptions, electrical characteristics criteria, details, and other provisions covered in this manual should be followed wherever practicable. The manual was prepared for use by engineers with basic knowledge of the profession, and judgment and discretion should be used in applying the material contained herein. In cases where preferred alternatives are not identified, designers should follow recommendations contained in the reference materials listed in the Bibliography that apply to the work to be performed.

b. Deviations from preferred methods. Departures from these guides may be necessary in some cases in order to meet special requirements or conditions of the work under consideration. When alternate methods, procedures, and types of equipment are investigated, final selection should not be made solely on first cost, but should be based on obtaining overall economy and security by giving appropriate weight to reliability of service, ease (cost) of maintenance, and ability to restore service within a short time in event of damage or abnormal circumstances. Whether architect-engineers or

Hydroelectric Design Center personnel design the power plant, the criteria and instructions set out in Appendix A of Guide Specification CE-4000 should be followed.

1-7. Hydroelectric Design Center (HDC)

The engineering of hydroelectric projects is a highly specialized field, particularly the engineering design and engineering support of operational activities. In order to assist field operating activities (FOA), the Corps of Engineers has established the Hydroelectric Design Center (HDC) as the center of expertise in the Corps of Engineers for this work. The FOA will retain complete responsibility and authority for the work, including funding, inspection, testing, contract management, and administration. The HDC will perform the following engineering and design services:

a. Provide the technical portions of reconnaissance reports and other pre-authorization studies for inclusion by the requesting FOA in the overall report.

b. Provide the architectural, structural, electrical, and mechanical design for the powerhouse including switchyards, related facilities, and all hydraulic transient studies.

c. Prepare preliminary design reports and the feature design memorandums for hydroelectric power plants for the requesting FOA.

d. Prepare plans and specifications for supply and construction contracts and supplemental major equipment testing contracts.

e. Provide technical review of shop drawings.

f. Provide technical assistance to the Contracting Officer’s representative at model and field tests. The HDC will analyze results and make recommendations.

g. Assist in preparation of Operation and Maintenance Manuals.

h. Provide necessary engineering and computer-aided drafting (CAD) work to incorporate “as-built” changes into the electronically readable “record” drawing files, and assure complete coordination for such changes.

i. Participate in review of plans and specifications for non-Federal development at Corps of Engineers projects in accordance with ER 1110-2-103.

Chapter 2
Basic Switching Provisions

2-1. One-Line Diagrams

a. General. The development of a plant electrical one-line diagram should be one of the first tasks in the preliminary design of the plant. In evaluating a plant for good electrical system design, it is easy to discuss system design in terms of the plant's one-line electrical diagram. The relationship between generators, transformers, transmission lines, and sources of station service power are established, along with the electrical location of the associated power circuit breakers and their control and protection functions. The development of the plant one-line diagram and the switching arrangement required to implement the one-line may help determine the rating of generators and consequently the rating of the turbines and the size of the powerhouse. In developing plant one-line diagram alternatives, use should be made of IEEE C37.2 to aid those reviewing the alternatives.

b. Evaluation factors. Some factors to consider in evaluating one-line diagrams and switching arrangements include whether the plant will be manned or unmanned, equipment reliability, whether the plant will be used in a "peaking" versus a base load mode of operation, the need to maintain a minimum flow past the plant, or whether there is a restriction on the rate of change of flow past the plant. The base load mode implies a limited number of unit start-stop operations, and fewer breaker operations than would be required for peaking operation. Unmanned operation indicates a need for reliable protection and control, and simplicity of operation. If there are severe flow restrictions, coupled with a need for continuous reliable power output, it may be necessary to consider the "unit" arrangement scheme because it provides the minimum loss of generation during first contingency disturbances.

c. Design characteristics. In general, a good plant electrical one-line should be developed with the goal of achieving the following plant characteristics:

(1) Safety and reliability.

(2) Simplicity of operation.

(3) Good technical performance.

(4) Readily maintainable (e.g., critical components can be removed from service without shutting down the balance of plant).

(5) Flexibility to deal with contingencies.

(6) Ability to accommodate system changes.

2-2. Plant Scope

a. Extent of project. When considering switching schemes, there are two basic power plant development scopes. Either the project scope will include a transmission-voltage switchyard associated with the plant or, electrically, the project scope ends at the line terminals of the high-voltage disconnect switch isolating the plant from the transmission line. Frequently, the Corps of Engineers project scope limit is the latter situation with the interconnecting switchyard designed, constructed, and operated by the Federal Power Marketing Agency (PMA), wielding the power or by the public utility purchasing the power through the PMA.

b. Medium-voltage equipment. Whether or not the scope includes a switchyard, the one-line development will involve the switching arrangement of the units, the number of units on the generator step-up (GSU) transformer bank, and the arrangement of power equipment from the generator to the low voltage terminals of the GSU transformer. This equipment is medium-voltage (0.6 *kv*-15 *kV*) electrical equipment. This chapter describes selection of appropriate switching schemes, including development of equipment ratings, economic factors, and operational considerations. Chapter 6, "Generator Voltage System," describes equipment types and application considerations in selecting the medium-voltage equipment used in these systems. Switching schemes for generating units and transformers may be of either the indoor or outdoor type, or a combination of both.

c. High-voltage equipment. When development does include a switchyard or substation, the same considerations apply in developing the generator voltage switching schemes described in paragraph 2-2*b*. Combined development does provide the opportunity to apply cost and technical trade-offs between the medium-voltage systems of the power plant and the high-voltage systems of the switchyard. Chapter 5, "High-Voltage System," describes switchyard arrangements, equipment and application considerations in developing the switchyard portion of the one-line diagram. Switchyards are predominately outdoor installations although in special cases (e.g., an underground power plant) high-voltage SF_6 insulated equipment systems may find use.

2-3. Unit Switching Arrangements

a. "Unit" arrangement. A "unit" scheme showing outdoor switching of the generator and transformer bank as a unit on the high-voltage side only, is shown in Figure 2-1a. The unit scheme is well-suited to small power systems where loss of large blocks of generation are difficult to tolerate. The loss of a transformer bank or transmission line in all other arrangements would mean the loss of more than a single generation unit. Small power systems are systems not able to compensate for the loss of multiple units, as could occur using other arrangements. The "unit" scheme makes maintenance outages simpler to arrange and is advantageous where the plant is located near the high-voltage substation making a short transmission distance. This scheme, with a transformer and transmission line for each generator unit, tends to be higher in first cost than schemes that have multiple generators on a single transformer and transmission line. Medium-voltage equipment for the unit systems includes bus leads from the generator to the GSU transformer and isolation disconnects for maintenance purposes.

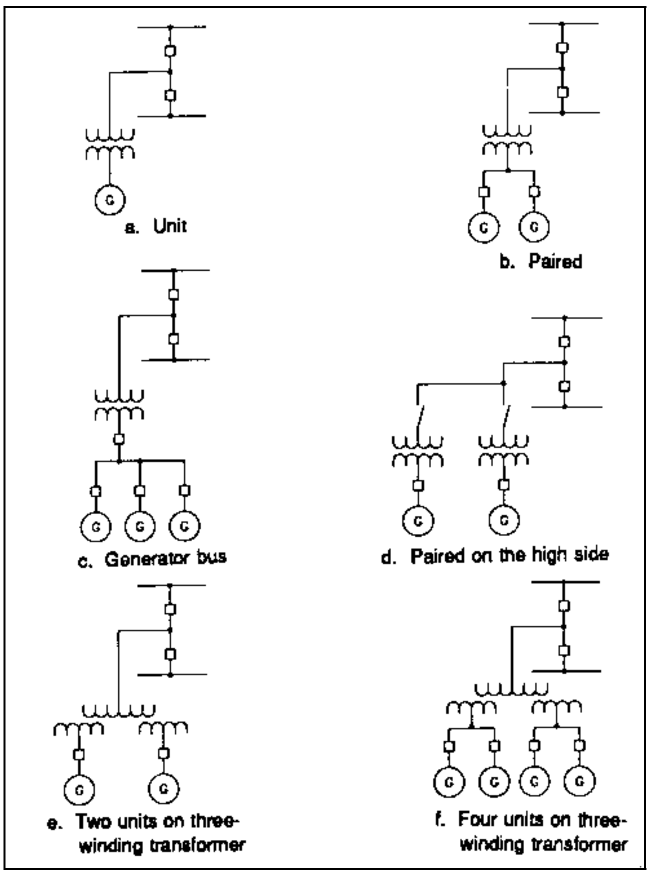

Figure 2-1. Main unit switching schemes

b. Multiple unit arrangements.

(1) In larger power systems, where loss of larger blocks of generation may be tolerable or where the plant is interconnected to an EHV grid (345 *kV* and above), two or more generators together with their transformer (or transformer bank) may be connected to one switchyard position. Some of the commonly used schemes are discussed in the following paragraphs. Refer to Chapter 3, "Generators" for discussion on the protection requirements for generator arrangements.

(2) Two generators may be connected to a two-winding transformer bank through Medium-Voltage Circuit Breakers (MVCBs) as shown on Figure 2-1b. This arrangement has the advantage of requiring a single transmission line for two units, rather than the two lines that would be required for a "unit" arrangement. This provides a clear savings in line right-of-way cost and maintenance. A single transformer, even though of higher rating, is also less costly than the two transformers that would be needed for a "unit" system. Again, the space requirement is also less than for two separate transformers. There are trade-offs: an MVCB for each generator is needed, the generator grounding and protection scheme becomes more complex, and additional space and equipment are needed for the generator medium-voltage (delta) bus. An economic study should be made to justify the choice of design, and the transformer impedance requirements should be evaluated if the power system is capable of delivering a large contribution to faults on the generator side of the transformer.

(3) For small generating plants, a scheme which connects the generators through MVCBs to the generator bus is shown in Figure 2-1c. One or more GSU transformers can be connected to the bus (one is shown), with or without circuit breakers; however, use of multiple transformers, each with its own circuit breaker, results in a very flexible operating arrangement. Individual transformers can be taken out of service for testing or maintenance without taking the whole plant out of service. The impedances of the transformers must be matched to avoid circulating currents. As noted above, the protection scheme becomes more complex, but this should be considered along with the other trade-offs when comparing this scheme with the other plant arrangements possible.

(4) Two or more generators can be connected to individual transformer banks through generator MVCBs with the transformers bused through disconnect switches on the high-voltage side as shown in Figure 2-1d. This arrangement has some of the advantages of the "unit" system shown in Figure 2-1a, and discussed above, along with the advantage of fewer transmission lines, which results in less right-of-way needs. There is some loss of operational flexibility, since transmission line service requires taking all of the units out of service, and a line fault will result in sudden loss of a rather large block of power. Again, needs of the bulk power distribution system and the economics of the arrangement must be considered.

(5) Two or more generators may be connected to a three-winding transformer bank as shown in Figure 2-1e and f. The generators would be connected to the two low-voltage windings through generator MVCBs. This arrangement allows specification of a low value of "through" impedance thus increasing the stability limits of the system and allowing the specification of a high value of impedance between the two low-voltage GSU transformer windings. This reduces the interrupting capacity requirements of the generator breakers. This scheme is particularly advisable when the plant is connected to a bulk power distribution system capable of delivering high fault currents. Again, transformer or line faults will result in the potential loss to the bulk power distribution system of a relatively large block of generation. Transformer maintenance or testing needs will require loss of the generating capacity of all four units for the duration of the test or maintenance outage. This scheme finds application where plants are interconnected directly to an EHV grid.

2-4. Substation Arrangements

a. General. High-voltage substation arrangements and application considerations are described in Chapter 5, "High-Voltage System." High-voltage systems include those systems rated 69 *kV* and above. The plant switching arrangement should be coordinated with the switchyard arrangement to ensure that the resulting integration achieves the design goals outlined in paragraph 2-1*c* in a cost-effective manner.

b. Substation switching. Some plants may be electrically located in the power system so their transmission line-voltage buses become a connecting link for two or more lines in the power system network. This can require an appreciable amount of high-voltage switching equipment. The desirability of switching small units at generator voltage should nevertheless be investigated in such cases. Chapters 5, "High-Voltage System" and 6, "Generator-Voltage System," discuss switching and bus arrangements in more detail.

2-5. Fault Current Calculations

a. General. Fault current calculations, using the method of symmetrical components, should be prepared for each one-line scheme evaluated to determine required transformer impedances, generator and station switchgear breaker interrupting ratings, and ratings of disconnect switches and switchyard components. Conventional methods of making the necessary fault current calculations and of determining the required ratings for equipment are discussed in IEEE 242 and 399. A number of software programs are commercially available for performing these studies on a personal computer. Two of these programs are: ETAP, from Operation Technology, Inc., 17870 Skypark Circle, Suite 102, Irvine, CA 92714; and DAPPER and A-FAULT, from SKM Systems Analysis, Inc., 225 S Sepulveda Blvd, Suite 350, Manhattan Beach, CA 90266.

b. Criteria. The following criteria should be followed in determining values of system short-circuit capacity, power transformer impedances, and generator reactances to be used in the fault current calculations.

(1) System short-circuit capacity. This is the estimated maximum ultimate symmetrical *kVA* short-circuit capacity available at the high-voltage terminals of the GSU transformer connected to the generator under consideration, or external to the generator under consideration if no step-up transformer is used. It includes the short-circuit capacity available from all other generators in the power plant in addition to the short-circuit capacity of the high-voltage transmission system. System short-circuit capacity is usually readily available from system planners of the utility or the PMA to which the plant will be connected.

(2) Calculating system short-circuit capacity. The transmission system short-circuit capacity can also be calculated with reasonable accuracy when sufficient information regarding the planned ultimate transmission system is available, including the total generating capacity connected to the system and the impedances of the various transmission lines that provide a path from the energy sources to the plant.

(3) Estimating power system fault contribution. When adequate information regarding the transmission system is unavailable, estimating methods must be used.

In all cases, the system short-circuit capacity for use in the fault current calculations should be estimated on a conservative basis, i.e., the estimate should be large enough to allow for at least a 50-percent margin of error in the system contribution. This should provide a factor of safety, and also allow for addition of transmission lines and generation capacity not presently planned or contemplated by system engineers and planners. Only in exceptional cases, such as small-capacity generating plants with only one or two connecting transmission lines, should the estimated ultimate system short-circuitry capacity be less than 1,000 *MVA*.

(4) Power transformer impedances.

(a) Actual test values of power transformer impedances should be used in the fault calculations, if they are available. If test values are not available, design values of impedance, adjusted for maximum IEEE standard minus tolerance (7.5 percent for two-winding transformers, and 10 percent for three-winding transformers and auto-transformers) should be used. Nominal design impedance values are contained in Table 4-1 of Chapter 4, "Power Transformers." For example, if the impedance of a two-winding transformer is specified to be 8.0 percent, subject to IEEE tolerances, the transformer will be designed for 8.0 percent impedance. However, the test impedance may be as low as 8.0 percent less a 7.5-percent tolerance, or 7.4 percent, and this lower value should be used in the calculations, since the lower value of impedance gives greater fault current.

(b) If the impedance of the above example transformer is specified to be not more than 8.0 percent, the transformer will be designed for 7.44 percent impedance, so that the upper impedance value could be 7.998 percent, and the lower impedance value (due to the design tolerance) could be as low as 6.88 percent, which is 7.44 percent less the 7.5 percent tolerance, which should be used in the calculations because the lower value gives a higher fault current. Using the lower impedance value is a more conservative method of estimating the fault current, because it anticipates a "worst case" condition. Impedances for three-winding transformers and auto-transformers should also be adjusted for standard tolerance in accordance with the above criteria. The adjusted impedance should then be converted to an equivalent impedance for use in the sequence networks in the fault current calculations. Methods of calculating the equivalent impedances and developing equivalent circuits are described in IEEE 242.

(5) Generator reactances. Actual test values of generator reactances should also be used in the calculations if they are available. If test values are not available, calculated values of reactances, obtained from the generator manufacturer and adjusted to the appropriate MVA base, should be used. Rated-voltage (saturated) values of the direct-axis transient reactance (X'_d), the direct-axis subtransient reactance (X''_d), and the negative-sequence reactance (X_2), and the zero-sequence reactance (X_o), are the four generator reactances required for use in the fault current calculations. If data are not available, Figure 3-2 in Chapter 3, "Generators," provides typical values of rated-voltage direct-axis subtransient reactance for waterwheel generators based on machine size and speed. Design reactance values are interrelated with other specified machine values (e.g., short-circuit ratio, efficiency) so revised data should be incorporated into fault computations once a machine has been selected.

Chapter 3
Generators

3-1. General

a. Design constraints. Almost all of the hydraulic-turbine-driven generators used in Corps' powerhouses will be synchronous alternating-current machines, which produce electrical energy by the transformation of hydraulic energy. The electrical and mechanical design of each generator must conform to the electrical requirements of the power distribution system to which it will be connected, and also to the hydraulic requirements of its specific plant. General Corps of Engineers waterwheel generator design practice is covered by the Guide Specification CW-16210.

b. Design characteristics. Since waterwheel generators are custom designed to match the hydraulic turbine prime mover, many of the generator characteristics (e.g., short-circuit ratio, reactances) can be varied over a fairly wide range, depending on design limitations, to suit specific plant requirements and power distribution system stability needs. Deviations from the nominal generator design parameters can have a significant effect on cost, so a careful evaluation of special features should be made and only used in the design if their need justifies the increased cost.

3-2. Electrical Characteristics

a. Capacity and power factor. Generator capacity is commonly expressed in kilovolt-amperes (*kVA*), at a given ("rated") power factor. The power factor the generator will be designed for is determined from a consideration of the electrical requirements of the power distribution system it will be connected to. These requirements include a consideration of the anticipated load, the electrical location of the plant relative to the power system load centers, and the transmission lines, substations, and distribution facilities involved. (See paragraph 3-2*f*).

b. Generator power output rating. The kilowatt rating of the generator should be compatible with the horsepower rating of the turbine. The most common turbine types are Francis, fixed blade propeller, and adjustable blade propeller (Kaplan). See detailed discussion on turbine types and their selection and application in EM 1110-2-4205. Each turbine type has different operating characteristics and imposes a different set of generator design criteria to correctly match the generator to the turbine. For any turbine type, however, the generator should have sufficient continuous capacity to handle the maximum horsepower available from the turbine at 100-percent gate without the generator exceeding its rated nameplate temperature rise. In determining generator capacity, any possible future changes to the project, such as raising the forebay level and increasing turbine output capability, should be considered. Figure 3-1 shows a typical capability curve for a hydroelectric generator.

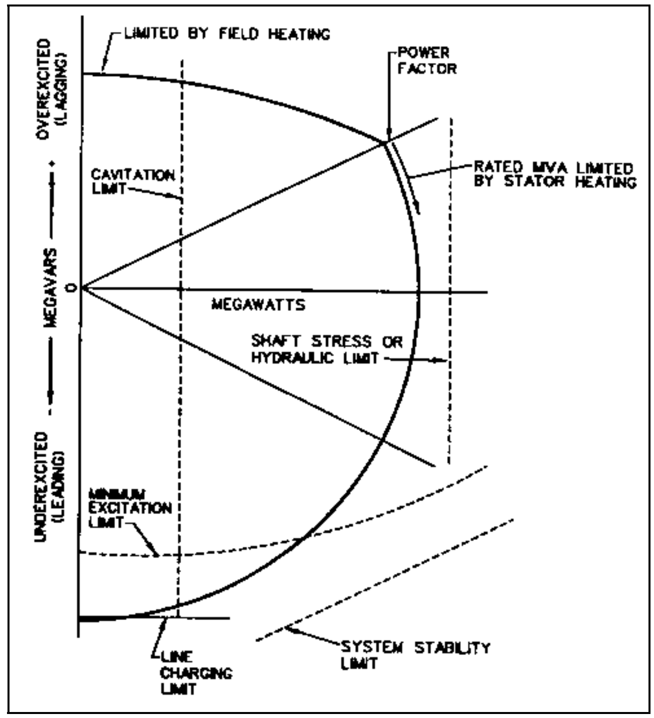

Figure 3-1. Typical hydro-generator capability curve

c. Generator voltage. The voltage of large, slow-speed generators should be as high as the economy of machine design and the availability of switching equipment permits. Generators with voltage ratings in excess of 16.5 *kV* have been furnished, but except in special cases, manufacturing practices generally dictate an upper voltage limit of 13.8 *kV* for machines up through 250 *MVA* rating. Based on required generator reactances, size, and Wk^2, a lower generator voltage, such as 6.9 *kV*, may be necessary or prove to be more economical than higher voltages. If the generators are to serve an established distribution system at generator voltage, then the system voltage will influence the selection of generator voltage, and may dictate the selection and arrangement of generator leads also. Generators of less than 5,000 *kVA* should preferably be designed for 480 V, 2,400 V, or 4,160 V, depending on the facilities connecting the generator to its load.

d. Insulation.

(1) The generator stator winding is normally supplied with either Class B or Class F insulation materials, with the insulation system meeting the temperature limits and parameters of ANSI C50.12 (e.g., 75 °C rise above a 40 °C ambient). The choice of insulation system types depends on machine size, how the machine will be operated, and desired winding life. Modern hydro units are subjected to a wide variety of operating conditions but specifications should be prepared with the intent of achieving a winding life expectancy of 35 or more years under anticipated operating conditions.

(2) The choice between Class B or Class F insulation systems for the stator winding will depend on the expected use of the generator. If it will be operated continuously at or near rated load, or has a high probability of operating overloaded for longer than 2 hr at a time, then the Class F insulation system should be specified. For generators that can be expected to be operated below rated load most of the time, and at or near full load for only limited periods, a Class B insulation system would be satisfactory. An insulation system using a polyester resin as a binder should be considered a Class B system, since the softening temperature of polyester resin is close to the Class F temperature limit.

(3) Stator winding insulation systems consist of a groundwall insulation, usually mica, with a suitable insulation binder, generally a thermosetting epoxy or polyester material. These thermosetting systems achieve dielectric strengths equivalent to that of older thermoplastic insulation systems with less thickness than the older systems, allowing the use of additional copper in a given stator slot, achieving better heat transfer, and permitting cooler operation. Thermosetting insulation systems tolerate higher continuous operating temperatures than older systems with less mechanical deterioration.

(4) Polyester resin has a lower softening temperature (known as the glass transition temperature, T_g) than the more commonly available epoxy insulation system, but it has the advantage of being slightly more flexible than the epoxy system. This slight flexibility is an advantage when installing multi-turn coils in stator slots in small diameter generators. The plane of the coil side coincides with the plane of the slot once the coil is installed. During installation, however, the coil side approaches the slot at a slight angle so that the coil must be slightly distorted to make the side enter the slot. Polyester is less likely to fracture than epoxy when distorted during installation. Polyester has no advantage over epoxy if the stator winding is of the Roebel bar type. Epoxy is usually preferred because of its higher T_g, and the polyester insulation system may not be available in the future.

(5) Thermosetting insulation system materials are hard and do not readily conform to the stator slot surface, so special techniques and careful installation procedures must be used in applying these materials. Corps guide specification CW-16210 provides guidance on types of winding and coil fabrication techniques, and installation, acceptance, and maintenance procedures to be used to ensure long, trouble-free winding life.

e. Short-circuit ratio.

(1) The short-circuit ratio of a generator is the ratio of the field current required to produce rated open circuit voltage, to the field current required to produce rated stator current when the generator output terminals are short-circuited. The short-circuit ratio is also the reciprocal of the per unit value of the saturated synchronous reactance. The short-circuit ratio of a generator is a measure of the transient stability of the unit, with higher ratios providing greater stability. Table 3-1 lists nominal short-circuit ratios for generators. Short-circuit ratios higher than nominal values can be obtained without much increase in machine size, but large values of short-circuit ratio must be obtained by trade-offs in other parameters of generator performance. Increasing the short-circuit ratio above nominal values increases the generator cost and decreases the efficiency and the transient reactance. Included in Table 3-1 are expected price additions to the generator basic cost and reductions in efficiency and transient reactance when higher than nominal short-circuit ratio values are required.

(2) In general, the requirement for other than nominal short-circuit ratios can be determined only from a stability study of the system on which the generator is to operate. If the stability study shows that generators at the electrical location of the plant in the power system are likely to experience instability problems during system disturbances, then higher short-circuit ratio values may be determined from the model studies and specified. If the power plant design is completed and the generators purchased prior to a determination of the exterior system connections and their characteristics, i.e., before the connecting transmission lines are designed or built, this will preclude making a system study to accurately determine the short-circuit ratio required. Where it is not feasible to determine the short-circuit ratio and there are no factors indicating that higher than nominal values are needed, then nominal short-circuit ratios should be specified.

Table 3-1
Generator Short-Circuit Ratios

	Short-Circuit Ratios at 0.8PF	0.9PF	0.95PF	1.0PF	Price Addition (Percent of Basic Price)	Reduction in Full-Load Efficiency	Multiplier For Transient Reactance
Normal	1.00	1.10	1.07	1.25	0	0.0	1.000
Not More Than	1.08	1.22	1.32	1.43	2	0.1	0.970
Not More Than	1.15	1.32	1.46	1.60	4	0.2	0.940
Not More Than	1.23	1.42	1.58	1.75	6	0.2	0.910
Not More Than	1.31	1.52	1.70	1.88	8	0.3	0.890
Not More Than	1.38	1.59	1.78	1.97	10	0.3	0.860
Not More Than	1.46	1.67	1.86	2.06	12.5	0.4	0.825
Not More Than	1.54	1.76	1.96	2.16	15	0.4	0.790
Not More Than	1.62	1.84	2.03	2.23	17.5	0.4	0.760
Not More Than	1.70	1.92	2.11	2.31	20	0.4	0.730
Not More Than	1.76	1.98	2.17	2.37	22.5	0.5	0.705
Not More Than	1.83	2.05	2.24	2.44	25	0.5	0.680
Not More Than	1.89	2.11	2.30	2.50	27.5	0.5	0.655
Not More Than	1.96	2.18	2.37	2.56	30	0.5	0.630
Not More Than	2.02	2.24	2.42	2.61	32.5	0.6	0.605
Not More Than	2.08	2.30	2.48	2.67	35	0.6	0.580
Not More Than	2.13	2.35	2.53	2.72	37.5	0.6	0.560
Not More Than	2.19	2.40	2.58	2.77	40	0.6	0.540
Not More Than	2.24	2.45	2.63	2.82	42.5	0.7	0.520
Not More Than	2.30	2.51	2.69	2.87	45	0.7	0.500
Not More Than	2.35	2.56	2.74	2.92	47.5	0.7	0.480
Not More Than	2.40	2.61	2.79	2.97	50	0.7	0.460
Not More Than	2.45	2.66	2.83	3.01	52.5	0.7	0.445
Not More Than	2.50	2.71	2.88	3.06	55	0.7	0.430

f. Line-charging and condensing capacities. Nominal values for these generator characteristics are satisfactory in all except very special cases. If the generator will be required to energize relatively long EHV transmission lines, the line-charging requirements should be calculated and a generator with the proper characteristics specified. The line-charging capacity of a generator having normal characteristics can be assumed to equal 0.8 of its normal rating multiplied by its short-circuit ratio, but cannot be assumed to exceed its maximum rating for 70 °C temperature rise. Often it will be desirable to operate generators as synchronous condensers. The capacity for which they are designed when operating over-excited as condensers is as follows, unless different values are specified:

Power Factor	Condenser Capacity
.80	65 percent
.90	55 percent
.95	45 percent
1.00	35 percent

g. Power factor.

(1) The heat generated within a machine is a function of its *kVA* output; the capacity rating of a generator is usually expressed in terms of *kVA* and power factor. (Larger machine ratings are usually given in *MVA* for convenience.) The kilowatt rating is the *kVA* rating multiplied by the rated power factor. The power-factor rating for the generator should be determined after giving consideration to the load and the characteristics of the system that will be supplied by the generator. The effect of power factor rating on machine capability is illustrated in Figure 3-1.

(2) The power factor at which a generator operates is affected by the transmission system to which it is connected. Transmission systems are designed to have resistive characteristics at their rated transmission capacities. Consequently, a generator connected to a transmission system will typically operate at or near unity power factor during maximum output periods. During lightly loaded

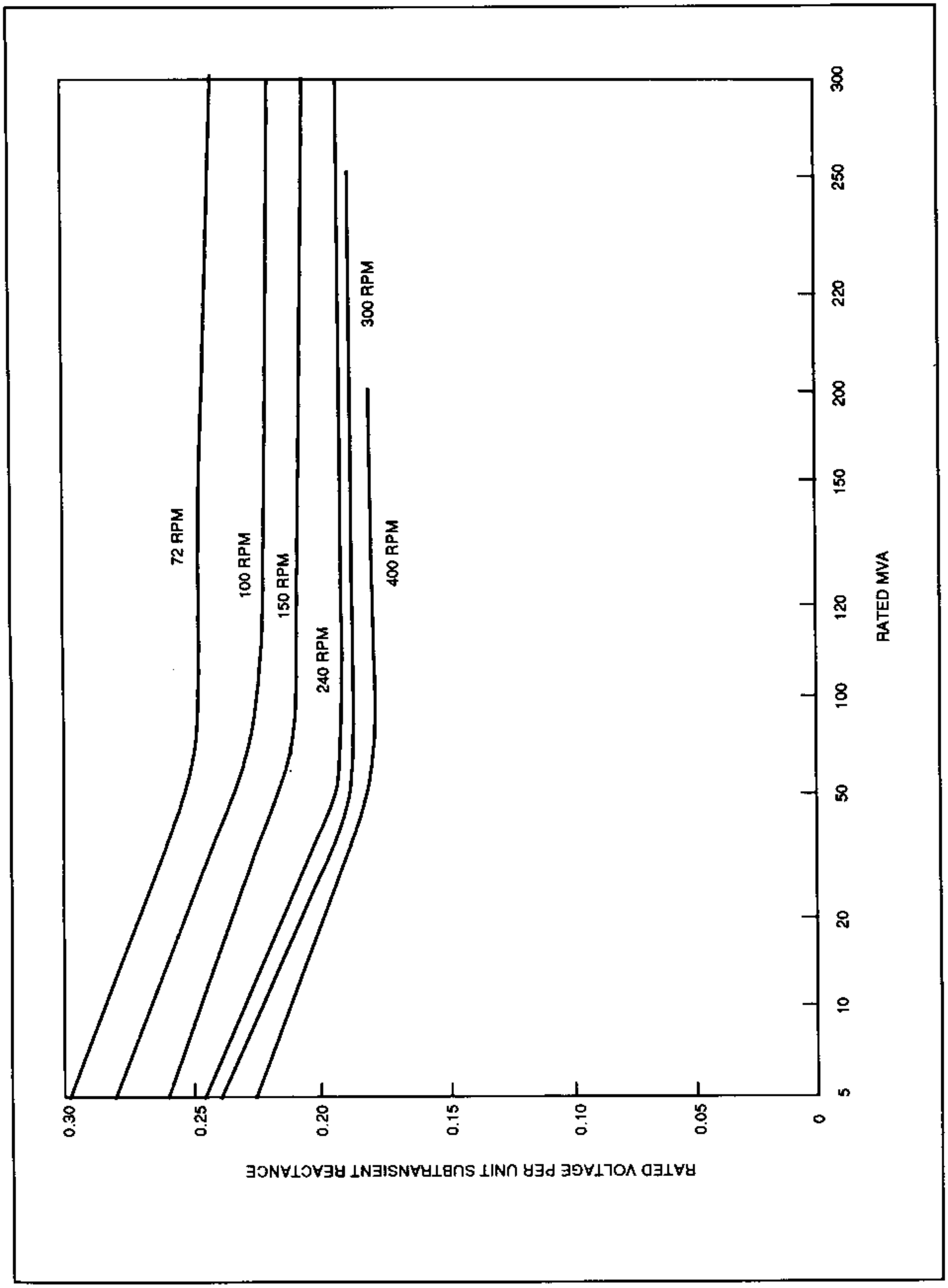

Figure 3-2. Typical generator transient reactances

conditions, however, the generator may be required to assist in transmission line voltage regulation. A generator operating on an HV transmission system with relatively short transmission distances will typically be required to supply reactive power (i.e., operate with a lagging power factor in an overexcited condition), due to the inductive characteristic of the unloaded transmission line. A generator operated on a long, uncompensated EHV transmission line will typically be required to absorb reactive power (i.e., operate with a leading power factor in an underexcited condition), due to the capacitive characteristic of the unloaded transmission line. In the latter case, the generator field current requirements are substantially below rated field currents, thus reducing the generator field strength. With reduced field strength, the generator operates closer to its stability limit (see Figure 3-1), making it more susceptible to loss of synchronism or pole slipping in the event of a system disturbance.

(3) It is highly desirable that the generator be designed for the power factor at which it will operate in order to improve system stability. In general, unless studies indicate otherwise, the power factor selected should be 0.95 for medium and large generators unless they will be at the end of a long transmission line, in which case a value approaching unity may be desirable.

h. Reactances.

(1) The eight different reactances of a salient-pole generator are of interest in machine design, machine testing, and in system stability and system stability model studies. A full discussion of these reactances is beyond the scope of this chapter, but can be found in electrical engineering texts (Dawes 1947; Fitzgerald and Kingsley 1961; Puchstein, Lloyd, and Conrad 1954), and system stability texts and standards (IEEE 399).

(2) Both rated voltage values of transient and subtransient reactances are used in computations for determining momentary rating and the interrupting ratings of circuit breakers. A low net through reactance of the generator and step-up transformer combined is desirable for system stability. Where nominal generator and transformer design reactances do not meet system needs, the increase in cost of reducing either or both the generator and transformer reactances and the selection of special generator reactance should be a subject for economic study. Such a study must include a consideration of space and equipment handling requirements, since a reduction in reactance may be accomplished by an increase in generator height or diameter, or both.

(3) Typical values of transient reactances for large water wheel generators indicated by Figure 3-2 are in accordance with industry standard practice. Guaranteed values of transient reactances will be approximately 10 percent higher.

(4) Average values of standard reactance will probably be sufficiently close to actual values to determine the rating of high-voltage circuit breakers, and should be used in preliminary calculations for other equipment. As soon as design calculations for the specific machine are available, the design values should be used in rechecking the computations for other items of plant equipment.

i. Amortisseur windings.

(1) Amortisseur windings (also referred to as damper windings in IEEE 399; Dawes 1947; Fitzgerald and Kingsley 1961; and Puchstein, Lloyd, and Conrad 1954) are essentially a short-circuited grid of copper conductors in the face of each of the salient poles on a waterwheel generator. Two types of amortisseur windings may be specified. In one, the pole face windings are not interconnected with each other, except through contact with the rotor metal. In the second, the pole face windings are intentionally connected at the top and bottom to the adjacent damper windings.

(2) The amortisseur winding is of major importance to the stable operation of the generator. While the generator is operating in exact synchronism with the power system, rotating field and rotor speed exactly matched, there is no current in the damper winding and it essentially has no effect on the generator operation. If there is a small disturbance in the power system, and the frequency tends to change slightly, the rotor speed and the rotating field speed will be slightly different. The rotor mass is perturbed when synchronizing power tends to pull the rotor back into synchronism with the system. That perturbation tends to cause the rotor-shaft-turbine runner mass to oscillate about its average position as a torsional pendulum. The result is relatively large pulsations in the energy component of the generator current. In worst case, the oscillations can build instead of diminishing, resulting in the generator pulling out of step with possible consequential damage.

(3) At the onset of the oscillations, however, the amortisseur winding begins to have its effect. As the rotating field moves in relation to the rotor, current is induced in the amortisseur windings. Induction motor

action results, and the rotor is pulled back toward synchronism by the amortisseur winding action.

(4) The amortisseur (damper) winding is of importance in all power systems, but even more important to systems that tend toward instability, i.e., systems with large loads distant from generation resources, and large intertie loads.

(5) In all cases, connected amortisseur windings are recommended. If the windings are not interconnected, the current path between adjacent windings is through the field pole and the rotor rim. This tends to be a high impedance path, and reduces the effectiveness of the winding, as well as resulting in heating in the current path. Lack of interconnection leads to uneven heating of the damper windings, their deterioration, and ultimately damage to the damper bars.

(6) The amortisseur winding also indirectly aids in reducing generator voltage swings under some fault conditions. It does this by contributing to the reduction of the ratio of the quadrature reactance and the direct axis reactance, X_q''/X_d''. This ratio can be as great as 2.5 for a salient pole generator with no amortisseur winding, and can be as low as 1.1 if the salient pole generator has a fully interconnected winding.

j. Efficiencies. The value of efficiency to be used in preparing the generator specification should be as high as can be economically justified and consistent with a value manufacturers will guarantee in their bids. Speed and power factor ratings of a generator affect the efficiency slightly, but the selection of these characteristics is governed by other considerations. For a generator of any given speed and power factor rating, design efficiencies are reduced by the following:

(1) Higher Short-Circuit Ratio (see paragraph 3-2*e*).

(2) Higher Wk^2 (see paragraph 3-5*b*).

(3) Above-Normal Thrust.

Calculated efficiencies should be obtained from the supplier as soon as design data for the generators are available. These design efficiencies should be used until test values are obtained.

3-3. Generator Neutral Grounding

a. General. The main reasons for grounding the neutrals of synchronous generators are to limit overvoltages on the generators and connected equipment under phase-to-ground fault conditions, and to permit the application of suitable ground fault relaying. Suitable neutral grounding equipment should be provided for each generator in hydroelectric power plants. The generator neutrals should be provided with current-limiting devices in the neutral circuits to limit the winding fault currents and resulting mechanical stresses in the generators in accordance with IEEE C62.92.2 requirements. Also, generator circuit breakers are designed for use on high impedance grounded systems, where the phase-to-ground short-circuit current will not exceed 50A. High impedance grounding with distribution transformers and secondary resistors is the method of choice for waterwheel generators.

b. Choice of grounding method. The choice of generator neutral grounding type for each installation, and the selection of the most suitable type and rating of neutral grounding equipment, should be made after preparation of fault current calculations and consideration of the following factors:

(1) Limitation of winding fault current and resulting mechanical stresses in the generator.

(2) Limitation of transient overvoltages due to switching operations and arcing grounds.

(3) Limitation of dynamic overvoltages to ground on the unfaulted phases.

(4) Generator surge protection (see paragraph 3-4).

(5) Generator ground fault relaying (see paragraph 8-6*b*(3)).

(6) Limitation of damage at the fault.

(7) Neutral switchgear requirements.

(8) Cost of neutral grounding equipment.

c. Solid neutral grounding. Solid neutral grounding is the simplest grounding method, since transient overvoltages and overvoltages to ground on the unfaulted phases during phase-to-ground faults are held to a minimum. Solid neutral grounding does produce maximum ground fault current and possible damage at the fault. Solid neutral grounding is not recommended.

d. Reactor neutral grounding. Reactor neutral grounding has certain desirable characteristics similar to those of solid neutral grounding. It is a preferred method of grounding in cases where a neutral current-limiting device is required to meet ANSI/IEEE short-circuit requirements and where the ratio of the zero sequence reactance to the positive sequence subtransient reactance at the fault does not exceed 6.0. Reactor neutral grounding limits transient overvoltages and overvoltages to ground on the unfaulted phases to safe values where the above reactance ratio does not exceed approximately 6.0. However, in most hydro applications, this reactance ratio approaches or exceeds 6.0, and since the high impedance distribution transformer-secondary resistor system is more economical, reactor neutral grounding does not find widespread use in hydro applications.

e. Resistor neutral grounding. Resistor neutral grounding can be considered in cases where solid neutral grounding or reactor neutral grounding would not be satisfactory; where several generators are paralleled on a common bus, especially in the case of generators of small or medium *kVA* rating; and where there are no exposed overhead feeders supplied at generator voltage. The resistor is usually rated to limit the generator neutral current during a phase-to-ground fault to a value between 100 and 150 percent of the generator full-load current. Possible damage at the fault is thus materially reduced, yet sufficient ground fault current is available to permit the application of satisfactory and selective ground fault relaying. The technique does produce high voltage to ground, exposing insulation systems of equipment connected to the generator to the possibility of insulation failure.

f. Distribution transformer-secondary resistor neutral grounding.

(1) This is the preferred method of generator neutral grounding and is, in effect, high-resistance neutral grounding. This is the method used in most North American hydro installations because the cost of grounding devices and neutral switchgear for other grounding methods is excessive due to the large values of ground fault current. It is also applicable to generators connected directly to delta-connected windings of step-up power transformers, especially where there are no overhead feeders supplied at generator voltage. The characteristics of this method of grounding, with respect to transient overvoltages to ground on the unfaulted phases and the requirement for the use of ungrounded-neutral rated surge arresters for generator surge protection, are similar to those of resistor neutral grounding.

(2) With this method of grounding, the generator neutral current, during a phase-to-ground fault, is limited to a very low value, usually between 5A and 15A, by the use of a relatively low-ohm resistor shunted across the secondary of a conventional step-down transformer whose primary is connected in the generator neutral circuit. The possible damage at the fault is therefore least of any of the various grounding methods. However, the type of generator ground fault relaying which can be applied has certain disadvantages when compared to the relaying which can be used with other grounding methods. Due to relatively low relay sensitivity, a considerable portion of the generator windings near the neutral ends cannot be protected against ground faults, the relaying is not selective, and the relay sensitivity for ground faults external to the generator varies greatly with the fault resistance and the resistance of the return circuit for ground fault current. The *kVA* rating of the grounding transformer should be based on the capacitive current which would flow during a phase-to-ground fault with the generator neutral ungrounded.

(3) Due to the relative infrequence and short duration of ground faults, a rating of 25 to 100 *kVA* is usually adequate for the transformer. The voltage rating of the transformer high-voltage winding should be equal to rated generator voltage, and the transformer low-voltage winding should be rated 240 V. The rating of the secondary resistor is based on making the resistor *kW* loss at least equal to the capacitive fault *kVA*.

g. Generator neutral equipment.

(1) An automatic air circuit breaker should be provided in the neutral circuit of each generator whose neutral is solidly grounded, reactor grounded, or resistor grounded. The circuit breaker should be a metal-clad, drawout type, either 1-pole or 3-pole, with a voltage rating at least equal to rated generator voltage, and with adequate ampere interrupting capacity, at rated voltage, for the maximum momentary neutral current during a single phase-to-ground fault. For generator neutral service, the circuit breakers may be applied for interrupting duties up to 115 percent of their nameplate interrupting ratings. When 3-pole breakers are used, all poles should be paralleled on both line and load sides of the breaker.

(2) A single-pole air-break disconnect should be provided in each generator neutral circuit using distribution transformer-secondary resistor type grounding. The disconnect should have a voltage rating equal to rated generator voltage, and should have the minimum available momentary and continuous current ratings. The disconnect, distribution transformer, and secondary resistor should be installed together in a suitable metal enclosure. The distribution transformer should be of the dry

type, and its specifications should require a type of insulation that does not require a heater to keep moisture out of the transformer.

3-4. Generator Surge Protection

a. Surge protection equipment. Since hydroelectric generators are air-cooled and physically large, it is neither practical nor economical to insulate them for as high impulse withstand level as oil-insulated apparatus of the same voltage class. Because of this and the relative cost of procuring and replacing (or repairing) the stator winding, suitable surge protection equipment should be provided for each generator. The equipment consists of special surge arresters for protection against transient overvoltage and lightning surges, and special capacitors for limiting the rate of rise of surge voltages in addition to limiting their magnitude.

b. Insulation impulse level. The impulse level of the stator winding insulation of new generators is approximately equal to the crest value of the factory low-frequency withstand test voltage, or about 40.5 *kV* for 13.8-*kV* generators. The impulse breakdown voltages for surge arresters for 13.8-*kV* generator protection are approximately 35 *kV* for 12-*kV* grounded-neutral rated arresters, and approximately 44 *kV* for 15 *kV* ungrounded-neutral rated arresters. Grounded-neutral rated surge arresters therefore provide better protection to generators than ungrounded-neutral rated arresters.

c. Grounded-neutral rated arresters. To correctly apply grounded-neutral rated arresters without an unacceptable risk of arrester failure, the power-frequency voltage applied across the arrester under normal or fault conditions must not exceed the arrester voltage rating. This requirement is usually met if the ratio of zero sequence reactance to positive sequence subtransient reactance at the fault, for a single phase-to-ground fault, does not exceed approximately 6.0. Since distribution transformer-secondary resistor grounding does not meet this requirement, only ungrounded-neutral rated surge arresters should be applied for generator surge protection.

d. Arrester arrangement. In most cases, one surge arrester and one 0.25-microfarad surge capacitor are connected in parallel between each phase and ground. In certain cases, however, such as the condition where the generators supply distribution feeders on overhead lines at generator voltage, or where two or more generators will be operated in parallel with only one of the generator neutrals grounded, two of the above capacitors per phase should be provided. A separate set of surge protection equipment should be provided for each generator. The equipment should be installed in metal enclosures located as close to the generator terminals as possible.

3-5. Mechanical Characteristics

The section of Guide Specification CW-16120 covering mechanical characteristics of the generator provides for the inclusion of pertinent data on the turbine. Since generator manufacturers cannot prepare a complete proposal without turbine characteristics, the generator specification is not advertised until data from the turbine contract are available.

a. Speeds.

(1) Hydraulic requirements fix the speed of the unit within rather narrow limits. In some speed ranges, however, there may be more than one synchronous speed suitable for the turbine, but not for the generator because of design limitations.

(2) Generators below 360 *r/min* and 50,000 *kVA* and smaller are nominally designed for 100 percent overspeed. Generators above 360 *r/min* and smaller than 50,000 *kVA* are generally designed for 80 percent overspeed. Generators larger than 50,000 *kVA*, regardless of speed, are designed for 85 percent overspeed. Because of the high overspeed of adjustable blade (Kaplan) turbines, in some cases more than 300 percent of normal, it may be impracticable to design and build a generator to nominal design limitations. Where overspeeds above nominal values are indicated by the turbine manufacturer, a careful evaluation of the operating conditions should be made. Also, the designer should be aware that turbine and generator overspeed requirements are related to the hydraulic characteristics of the unit water inlet structures. Hydraulic transients that might result from load rejections or sudden load changes need to be considered.

(3) Generators for projects with Kaplan turbines have been designed for runaway speeds of 87-1/2 percent of the theoretical maximum turbine speed. In accordance with requirements of Guide Specification CW-16120, the stresses during design runaway speeds should not exceed two-thirds of the yield point. However, where the design overspeed is less than the theoretical maximum runaway speed, calculated stresses for the theoretical maximum speed should be less than the yield points of the materials.

b. Flywheel effect.

(1) The flywheel effect (Wk^2) of a machine is expressed as the weight of the rotating parts multiplied by the square of the radius of gyration. The Wk^2 of the generator can be increased by adding weight in the rim of the rotor or by increasing the rotor diameter. Increasing the Wk^2 increases the generator cost, size, and weight, and lowers the efficiency. The need for above-normal Wk^2 should be analyzed from two standpoints, the effect on power system stability, and the effect on speed regulation of the unit.

(2) Electrical system stability considerations may in special cases require a high Wk^2 for speed regulation. As Wk^2 is only one of several adjustable factors affecting system stability, all factors in the system design should be considered in arriving at the minimum overall cost. Sufficient Wk^2 must be provided to prevent hunting and afford stability in operation under sudden load changes. The index of the relative stability of generators used in electrical system calculations is the inertia constant, H, which is expressed in terms of stored energy per kVA of capacity. It is computed as:

$$H = \frac{kW \cdot s}{\text{kVA}} = \frac{0.231\ (Wk^2)\ (r/min)^2 \times 10^{-6}}{kVA}$$

(3) The inertia constant will range from 2 to 4 for slow-speed (under 200 r/min) water wheel generators. Transient hydraulic studies of system requirements furnish the best information concerning the optimum inertia constant, but if data from studies are not available, the necessary Wk^2 can be computed or may be estimated from a knowledge of the behavior of other units on the system. Estimates of the effect of increased Wk^2 on the generator base cost are indicated by Figure 3-3.

(4) The amount of Wk^2 required for speed regulation is affected by hydraulic conditions (head, length of penstock, allowable pressure rise at surge tank, etc.) and the rate of governor action. The speed increase when full load is suddenly dropped should be limited to 30 to 40 percent of normal speed. This allowable limit may sometimes be increased to 50 percent if the economics of the additional equipment costs are prohibitive. When station power is supplied from a main generator, the effect of this speed rise on motor-driven station auxiliaries should be considered. Smaller generators servicing isolated load blocks should have sufficient Wk^2 to provide satisfactory speed regulation. The starting of large motors on such systems should not cause a large drop in the isolated system frequency.

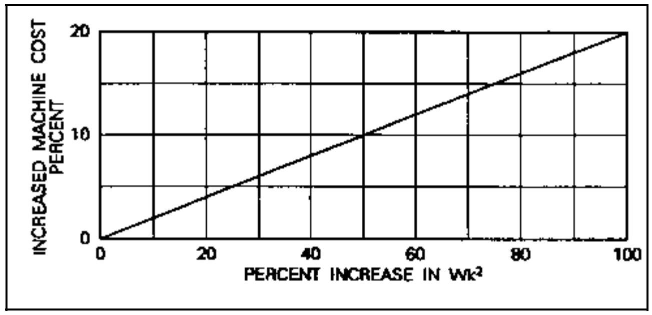

Figure 3-3. Effect of increased Wk^2 on generator cost (included by permission of Westinghouse Electric Corp)

(5) The measure of stability used in turbine and governor calculations is called the flywheel constant and is derived as follows:

$$\text{Flywheel Constant} = \frac{(Wk^2)\ (r/min)^2}{hp}$$

If the horsepower (hp) in this formula is the value corresponding to the kVA (at unity power factor) in the formula for the inertia constant (H), the flywheel constant will be numerically equal to 3.23×10^6 multiplied by the inertia constant. As the actual turbine rating seldom matches the generator rating in this manner, the flywheel constant should be computed with the above formula.

c. Cooling.

(1) Losses in a generator appear as heat which is dissipated through radiation and ventilation. The generator rotor is normally constructed to function as an axial flow blower, or is equipped with fan blades, to circulate air through the windings. Small- and moderate-size generators may be partially enclosed, and heated generator air is discharged into the generator hall, or ducted to the outside. Larger machines are enclosed in an air housing with air/water heat exchangers to remove heat losses.

(2) Open cooling systems are normally adequate for small- and medium-size generators (less than 10 MW). If special ventilating and air cleaning equipment is required to accommodate an open cooling system, the cost of these features should be compared against the cost of having a generator with a closed air recirculating system with air/water heat exchangers.

(3) An enclosed air housing with a recirculated air cooling system with air/water heat exchangers is preferred for units of 10 MW and larger. Cooling of the generator

can be more easily controlled with such a system, and the stator windings and ventilating slots in the core kept cleaner, reducing the rate of deterioration of the stator winding insulation system. The closed system also permits the addition of automatic fire protection systems, attenuates generator noise, and reduces heat gains that must be accommodated by the powerhouse HVAC system.

(4) Water-cooled heat exchangers used in a recirculated air cooling system consist of groups of thin-walled finned tubes with appropriate water boxes, valves, and headers. Standard air coolers are designed for 50-pound-per-square-inch (psi) working pressure, but can be supplied for 100-psi working pressure for a slightly higher price. The 100-psi rated coolers should be used where the hydraulic head of the cooling water source is greater than 100 ft. For best service, tube sheets of 90/10 Cu/Ni should be used for air and bearing lube oil coolers. The turbine spiral case is normally used as the cooling water source for projects with heads of up to 250 ft. Where project head exceeds approximately 250 ft, pumped systems using a tailwater source are preferred.

(5) The design pressure for the stator heat exchangers should be based on pump shut-off head if a pumped source of cooling water is used. Design pressure for spiral case cooling water sources should be based on maximum project pool level, plus a surge allowance. Heat exchanger hydrostatic tests should be performed at pressures of 150 percent of rated pressure. Design cooling water temperature should be the maximum temperature of the cooling water source, plus a contingency allowance.

(6) The water supply line to the air coolers should be separate from the water line to the thrust-bearing cooler. It may prove desirable to modulate the water flow to the air coolers to control the generator temperature, or to shut it off entirely when the unit is being stopped. It is desirable to keep a full flow of water through the thrust bearing oil cooler whenever the unit is turning. Each cooling water supply line should be equipped with a flow indicator. The flow indicator should be equipped with an alarm contact for low flow.

(7) Each air cooler should be equipped with water shut-off valves so a cooler can be cut out if in trouble, or be serviced while the generator is operating. Coolers should be designed with as great a number of heat exchanger tubes in the air flow passage as practical in order to reduce water usage. Adequate floor drains inside the air housing should be provided to remove any water that may condense on or leak from the coolers. The unit drain header should empty into the tailwater if plant conditions permit, but the drain should not be terminated where it will be subject to negative pressures from the draft tube, since this will impose negative pressures on the heat exchangers.

(8) Heated air from the generator enclosure should not be used for plant space heating because of the possibility of exposure of plant personnel to ozone, and the possibility of CO_2 being discharged into the plant. Water from the coolers may be used as a heat source in a heat pump type of heating system, but if water flow modulation is used, there may not be enough heat available during periods of light loading, or when the plant is shut down.

d. Weights and dimensions.

(1) Estimating weights and dimensions of the generators should be obtained from generator manufacturers for plant design purposes. These figures should be rechecked after bid data are available on the particular generator selected. The contemplated speed, Wk^2, short-circuit ratio, reactance, and over-speed are the usual factors that have the greatest effect on weight variation. Where a high value Wk^2 is required, a machine of the next larger frame size with consequent increase in diameter may be required.

(2) Dimensions of the rotor and the method of assembling the rotor and the shaft in the generator have an important bearing on crane clearances. The number and location of air coolers and the shape of the air housing on a generator with the closed type of cooling system should be studied for their effect on the dimensions of the generator room. Generator and turbine access should be considered, as well as the possible need for suppressing noise radiated into the powerhouse.

3-6. Excitation Systems

a. General. Current practice in the design of Corps of Engineers power plants is to use solid state bus-fed excitation systems for the generator exciter and voltage regulator function. Solid state excitation systems currently available from reputable manufacturers exhibit reliability comparable to, and in some cases better than, older mechanical systems. Excitation system specifications should be carefully prepared, with attention to requirements of the power system to which the generator will be connected.

b. Large generators.

(1) The stability of a large turbine-generator set while connected to its power system is critically important. However, the designer must also consider the unit's characteristics when operating alone, or in an isolated "island" much smaller than the normal power system.

(2) One example of a unit operating alone is a main unit serving as the station service source in a plant that becomes separated from its power distribution system. The unit will have to accept motor starting loads, and other station service demands such as gate and valve operation, while maintaining a safe and stable output voltage and frequency. All this will be accomplished while operating at a fraction of its rated output.

(3) When operating in an "island," the unit may be required to operate in parallel with other units while running at speed-no-load in order to provide enough capacity to pick up blocks of load without tripping off line. In this case, stable operation without the stabilizing effect of a very large system is critically important to restoring service, and putting the system back together.

c. Small units. For small units producing energy for a very large system, stability is not so critical since system voltage support will be beyond the small unit's capability. Nonetheless, for its own safe operation, good voltage control is important. An extremely high response system is not necessary, but the system should respond rapidly enough to prevent dangerous voltage excursions.

d. Excitation system characteristics.

(1) In general, there are two types of static excitation systems: one using a full-inverting power bridge, and the other using a semi-inverting power bridge. The full-inverting system uses six (or more) silicon controlled rectifiers (SCRs) in the power bridge so the generator field voltage can be forced both positive and negative. The semi-inverting system allows the generator field voltage to be forced positive, and reduced to zero.

(2) The full-inverting bridge allows boost and buck operation much like that available in older systems, but with the potential for a faster response. Faster response means less phase shift in the control action, and the reduction of phase shift permits control action to increase the stability of voltage regulation (see also paragraph 3-6*g*(6)).

(3) Dips in output voltage can be reduced, and voltage recovery speed improved, with the field forcing function. Increasing the field voltage helps greatly in overcoming the lag caused by the inductance of the generator field, and increases the speed of response of generator output voltage to control action. However, the exciter ceiling voltage (maximum forcing voltage available) to the generator field must be limited to a value that will not damage field insulation. The manufacturer will determine the exciter ceiling voltage based on the nominal response specified.

(4) The semi-inverting system also provides for fast response, but without the capability to force the field voltage negative with respect to its normal polarity. This slows the generator output voltage response capability. One or more diodes provide a path for decaying field current when the AC contactor is opened.

(5) Power system requirements and machine voltage performance during unit load rejections should be considered in evaluating the use of a semi-inverting system. If stability requirements can be met and adequate voltage performance maintained during unit load rejections, then either a semi-inverting or a full-inverting system is acceptable. If either criterion appears compromised, a full-inverting system is recommended.

(6) If the particular generator (or plant) in question has sufficient capacity to affect the control area to which it is connected, a full-inverting voltage regulating system would be justified if the control area has a high ratio of energy import (or export) to load, and is marginally stable or experiences tie line separations. A full-inverting system can force voltage down if an export tie line is lost, and can force generator voltage down if the machine is suddenly tripped off line while carrying a substantial load. Both cases will reduce voltage stresses on the generator; the first example will assist in maintaining system stability, the second will help protect the generator winding from dangerous overvoltages.

e. Excitation system arrangement.

(1) In general, bus-fed solid state excitation systems are made up of three elements: the power potential transformer (PPT), the power bridge (or rectifier), and the control section (voltage regulator function).

(2) Location of the PPT will depend on the supply source chosen. If power to the PPT is supplied from the

generator leads, the bus arrangement will be affected, and that must be considered in the initial design and layout of the powerhouse. If the PPT is fed from the generator delta bus, its location must be selected so that it will be reasonably close to the power bridge equipment. The PPT should be specified to be self-cooled, and the designer should consider this in determining its location.

(3) For either power source to the PPT, protection should be provided by current-limiting fuses. The available fault current at the input to the PPT will be quite large, so it will be necessary to limit it to prevent destructive releases of energy at the fault location. Current-limiting fuses also provide circuit clearing without current surges that can cause voltage transients which are dangerous to the integrity of the generator insulation. When the fusible element melts, the fuse essentially becomes a resistor in series with the fault. Voltage and current across the resistor are thus in phase, and the circuit is cleared at the first zero crossing, without danger of arc restrike (if the fuse works properly).

(4) The excitation system should also provide for a means of disconnecting power from the generator field. In general, this requires that power be interrupted at the bridge input, at the generator field input, or at both places, and that a means of dissipating energy stored in the field be provided. Energy dissipation is a major consideration, because without it the field inductance will cause field voltage to rise sharply when field current is interrupted, possibly rupturing the field insulation. Several methods exist to perform the field removal function.

(a) One method of field removal for a semi-inverting system uses a contactor in the AC input to the power bridge. For field discharge, a diode (called a free-wheeling diode) can be used to provide a path for the field current to dissipate field energy. Another method is to provide a shorting contact in series with a discharge resistor across the generator field. When the Device 41 AC breaker opens, the auxiliary Device 41 shorting contact closes.

(b) A method which can be used with a full-inverting bridge uses a field breaker and discharge resistor. This is a straightforward method where the power from the bridge to the field is interrupted, and the field is simultaneously short-circuited through a discharge resistor.

(c) With either a semi- or full-inverting bridge, it is possible to use a device 41 in the DC side of the bridge, with a thyristor element to control field energy dissipation. The thyristor device is a three- (or more) junction semiconductor with a fast OFF to ON switching time that is capable of going to the conducting state within a very short time (about one quarter of a cycle) after the Device 41 opens.

(d) With either a semi- or full-inverting bridge, it is possible to use a device 41 in the AC (input) side of the bridge, with a thyristor element to control field energy dissipation. The thyristor device is a three- (or more) junction semiconductor with a fast OFF to ON switching time that is capable of going to the conducting state within a very short time (about one quarter of a cycle) after the Device 41 opens.

(5) Power bridge equipment should be housed in a cubicle by itself, for safety and reduction of electromagnetic noise, and be located near or beside the excitation control cubicle. Both cubicles should be designed for reduction of radiated electromagnetic interference (EMI).

(6) The power electronics equipment in the excitation system can be either fan-cooled or self-cooled. Fan-cooled excitation systems are usually smaller than self-cooled systems, but require extra equipment for the lead-lag fan controls. Fan-cooled excitation systems may require additional maintenance resulting from such things as fans failing to start, air flow switches failing, fan air flow causing oil from the turbine pit to be deposited on filters, and worn-out fan motors causing noise to be applied to the regulator control system. Self-cooled excitation systems may require larger cubicles and higher-rated equipment to allow for heat transfer. On large generators, it may not be practical to use a self-cooled system. On smaller units it may be preferable. Each unit should be judged on its life cycle costs.

(7) If the capability of connecting a unit to a de-energized transmission system will be necessary (“black start” capability), there may be a requirement for operating the generator at around 25 percent of nominal voltage to energize transformers and transmission lines without high inrush currents. This requirement may impose the need for an alternate power source to the PPT since the power bridge might not operate reliably at reduced voltage levels. If an alternate supply source is needed, provide switching and protection, and ensure that the normal PPT source and the emergency source cannot be connected in parallel. The power transmission authority should be consulted to determine the voltage necessary for charging lines and transformers to re-energize a power system. Requiring additional power sources not only adds costs to the project, but complexity to the system, which may not be justified. The complexity of a system is

usually proportional to its maintenance, failure, and misoperation rate.

f. Excitation system regulators.

(1) The voltage regulator function of modern solid state excitation equipment is an integral part of the system, and will use digital control elements with microprocessor-based control. This type of control provides far more flexibility in changing regulator characteristics than the older mechanical element type of control. It also provides more precise and predictable control action, and will require far less maintenance.

(2) The voltage regulator function should provide automatic and manual control of generator output voltage, with “bumpless” transfer between modes, over a range of at least plus or minus 10 percent from nominal generator voltage. The bumpless transfer requirement means that the regulator control modes must track each other so that when the control mode is switched the generator voltage (or reactive output) will not exhibit a step change of any magnitude.

(3) Voltage regulator control to maintain generator power factor, or maintain a selected var loading may also be required. If the plant is to have an automatic control system, provisions should be required for control inputs to the regulator, and it may be possible to dispense with some of the regulator control features, particularly if the plant will not be manned.

g. Excitation system accessories.

(1) An AC input voltmeter, a DC output (field voltage) voltmeter, and a DC field ammeter are accessories that should be considered essential for a quick check on system operation. Rectifier failure detection should also be considered, particularly for units controlled remotely.

(2) Remotely operated controls are also essential for units controlled from locations remote from the unit switchboards. Maximum and minimum excitation limiter equipment should also be provided in all cases. This equipment is critical to units that are direct connected with other units on a common bus.

(3) Momentary connection of a DC source of proper polarity to the generator field (field flashing) should also be required. Field flashing provides prompt and reliable buildup of generator voltage without reliance on residual magnetism. Include protection against overlong application of the flashing source. The simplest source for field flashing voltage is the station battery. If the unit is not required to have black start capability, an alternative to using the station battery is to use an AC power source with a rectifier to furnish the necessary DC power for field flashing. This alternative source could be considered if it is determined to be significantly more economical than providing additional station battery capacity. Depending on the design, this alternative could require additional maintenance in the long term for short-term cost reductions. Project life cost should be considered when evaluating the sources of field flashing. A rectifier can be used as the DC source if the station battery size can be reduced enough to provide economic justification.

(4) Reactive droop compensation equipment is needed for units operated in parallel on a common low-voltage bus to prevent unequal sharing of reactive load. Reactive droop compensation reduces the generator output voltage slightly as reactive output increases. The net effect is to stabilize unit operation when operating in parallel and tending to prevent var load swings between units.

(5) Active droop compensation (or “line drop” compensation) is simply a means of artificially relocating the point where the generator output voltage is sensed for the voltage regulation function. It consists of increasing the generator output voltage in proportion to output current, to compensate for the voltage drop between the generator output terminals and the desired point on the system. Active droop compensation should be considered if the generator is connected to the system through a high impedance unit transformer or to a long high-impedance transmission line. Line drop compensation is usually not required unless needed for power transmission system voltage stability. This requirement will be established by the power transmission authority. When used with automatic voltage control that derives its controlled-value input from the same, or nearly the same, point as the line drop compensation feature, caution should be used to ensure that the automatic voltage control system is not counteracting the effects of the voltage regulator line drop compensation feature. Close coordination with the power transmission authority is required to ensure power system voltage stability.

(6) Power System Stabilizer (PSS) equipment should be used on generators large enough to have a positive effect on power system stability. The PSS function tends to damp out generator rotor oscillations by controlling the excitation system output in phase opposition to power system oscillations to damp them out. PSS works by sensing an input from the power system and reacting to

oscillations in the power system. These oscillations typically show up in the unit as rotor angle oscillations and if allowed to continue to build up in conjunction with other synchronous machines in the system, set up unacceptable power swings between major loads and major generating plants in a widely dispersed power distribution grid.

h. Excitation system instrument transformers. Dedicated current and potential transformers should be supplied to service the excitation system voltage regulators. They can often be advantageously mounted in metal-clad switchgear, cubicles, or metal-enclosed bus runs, where they are associated with similar instrument transformers for metering and relay service. The latter are furnished and mounted by the manufacturer of the cubicles or buses, and a better layout can usually be devised, where all instrument transformers are of the same general form, than would result if space were provided for field installation of transformers supplied with the voltage regulator. Multiple-secondary current transformers save considerable space. The guide specifications provide for alternate methods of procurement, assuming that the general design of buses and generator leads will have been determined before the generator is awarded.

3-7. Generator Stator

a. Stator core stampings. The stator primary component is the thin sheet steel stampings that, when stacked together and clamped, form the stator core. The stamping shapes are so designed that when they are correctly stacked, they will form stator winding coil slots, with no stamping protruding into the slot. Uneven slots are detrimental to coil life in several ways: wear on ground wall insulation armor tape; prevention of adequate tightening of coil in the slot; and, in extreme cases, erosion of the ground wall insulation.

b. Stator frame.

(1) The stator frame is designed for rigidity and strength to allow it to support the clamping forces needed to retain the stator punchings in the correct core geometry. Strength is needed for the core to resist deformation under fault conditions and system disturbances. Also, the core is subjected to magnetic forces that tend to deform it as the rotor field rotates. In a few large size machines, this flexing has been known to cause the core to contact the rotor during operation. In one instance, the core deformed and contacted the rotor, the machine was tripped by a ground fault, and intense heating caused local stator tooth iron melting, which damaged the stator winding ground wall insulation.

(2) Even if the rotor and the stator core do not come in contact, the varying air gap is a problem. In machines with split phase windings where the split phase currents are monitored for machine protection, the variation in the air gap causes a corresponding variation in the split phase currents. If the variations are significant, the machine will trip by differential relay action, or the differential relays will have to be desensitized to prevent tripping. Desensitizing the relays will work, but it reduces their effectiveness in protecting the machine from internal faults.

(3) Further reading on this subject can be found in the IEEE Transactions on Power Apparatus and Systems, Vol PAS-102, Nos. 9 and 10, and in the AIEE Transactions of October 1953, as Paper 53-314.

c. Stator assembly. Small stator assemblies that can be shipped in one or two pieces should be completely assembled at the factory. If the stator frame assembly has to be shipped in more than two pieces, the core should probably be stacked in the field. Field stacking will avoid splits in the stator core, the major source of stator core problems. Stator frames are generally built at the factory in sections that are as large as can be shipped to the erection site. Stator assembly is completed in the field by bolting the sections together, stacking the core iron laminations, and winding the stator. Field stacking of the stator core results in a higher initial cost for the generator, but provides better service life and is preferred. Generator Guide Specification CW-16120 contains a discussion on stator assembly.

d. Multiturn coil stator windings. On smaller generators, and on certain sizes of larger machines, stator windings employing multiple turn coils are used. This effectively inserts more coils per armature slot, giving a higher generated voltage per slot as compared with a single turn bar winding. With this winding design, the stator winding is divided into two or more parallel paths per phase. On the neutral ends of the winding, one half of each phase is connected to the ground point through a current transformer (CT) of carefully selected ratio and characteristics. On the generator output, other CTs measure the total phase current. Differential relays compare the split phase current and total phase current; an internal generator fault that results in unbalanced current between the phase halves can usually be detected and the unit tripped off quickly enough to prevent serious damage.

e. Roebel bar stator windings. For large generators, winding designs using single turn coils are preferred, in which case the neutral terminals are not divided and a different arrangement of CTs for the differential relays is required. The single turn coils use a Roebel transposition, rather than separate turns, to balance current in the conductors. This eliminates the possibility of turn-to-turn faults, which are a common cause of winding failures. Single turn coils cannot be used on machines with short bore heights because there is not sufficient room to make the Roebel transposition. There are also certain configurations of large machines which do not allow the use of single turn coils.

3-8. Rotor and Shaft

a. Rotor assembly.

(1) Large generator rotors must be assembled in the powerhouse. Manufacturing practice provides two types, one in which the hub and arms are made of cast steel, the other with a cast or fabricated hub to which are bolted and keyed the fabricated rotor arms. For rotors with bolted-on arms, a means of access to inspect and re-tighten the bolts should be specified. Some medium-sized units have been built with rotors of stacked sheets, but this type is limited by the rolling width of the sheets. With both types the rotor rim is built up of sheet steel punchings.

(2) Pole pieces, assembled and wound in the factory, are usually made with a dovetail projection to fit slots in the rim punchings. The pole pieces are assembled to the rotor using wedge-shaped keys, two keys per pole piece. The field assembly program should make provisions for handling large pole pieces without tying up the powerhouse bridge crane.

b. Generator shafts.

(1) Generator shafts 12-in. and larger diameter should be gun-barrel drilled full length. This bore facilitates inspection of the shaft forging, and in the case of Kaplan units, provides a passage for the two oil pipes to the blade servo-motor in the turbine shaft.

(2) Generators designed with the thrust bearing located below the rotor usually have either a bolted connection between the bottom of the rotor hub and a flange on the shaft, or the shaft projects through a hole in the hub and is keyed to it. Provisions in the powerhouse for rotor erection should consider the floor loading of the rotor weight, concentrated on the area of the shaft hub or the rotor flange, supported by the powerhouse floor. Include a plate in the floor (included with the generator specifications and to be supplied by the generator manufacturer) to which the rotor hub or shaft flange can be bolted.

(3) If the design of the rotor and shaft provides for a permanent connection between the shaft and rotor hub, it may be necessary to locate the rotor erection plate in a floor recess, or on a pedestal on the floor below the erection space, under a hole in the floor provided for the shaft. Also, if the complete rotor is to be assembled on a long shaft which extends below the rotor hub before the shaft and rotor are placed in the stator, it may be convenient to provide a hole in the erection floor so that the lower end of the shaft will rest on the floor below, thus minimizing the crane lift during rotor assembly. When the shaft must be handled with the rotor in assembling the generator, the crane clearance above the stator frame may be affected.

3-9. Brakes and Jacks

The brakes, which are used to stop rotation of the unit, are actuated by 100-psi air pressure and are designed to serve as rotor jacks when high-pressure oil is substituted for air. As far as the generator alone is concerned, the distance the rotor is to be lifted by the jacks depends on the space required to change a thrust bearing shoe. Blocks should be provided to hold the rotor in the raised position without depending on the jacks. The usual lift required to service a bearing is approximately 2 in. If the generator is to be driven by a Kaplan turbine, the lift must provide space for disconnecting the Kaplan oil piping. This lift may be as much as 12 in. The generator manufacturer can usually design for this extra lift so nothing on the generator need be disturbed except to remove the collector brush rigging. Motor-operated jacking oil pumps can be permanently connected to large units. Medium-sized and smaller generators can be served with a portable motor-operated oil pump. Motor-operated pumps should be provided with suitable oil supply and sump tanks so the oil system will be complete and independent of the station lubricating oil system.

3-10. Bearings

a. Thrust bearing loading. The thrust bearing in the generator is the most important bearing element in the generator-turbine assembly as it carries not only the weight of the rotating generator parts, but the weight of the turbine shaft and turbine runner, in addition to the hydraulic thrust on the runner. The allowable hydraulic thrust provided in standard generator design is satisfactory for use with a Francis runner, but a Kaplan runner requires provision for higher-than-normal thrust loads. It is important that the generator manufacturer have full and accurate information regarding the turbine.

b. Thrust bearing types. The most commonly used types of thrust bearings are the Kingsbury, the modified Kingsbury, and the spring-supported type. The spherical type of thrust bearing has not been used on any Corps of Engineers' generators. All of these types have the bearing parts immersed in a large pot of oil that is cooled either by water coils immersed in the oil or by the oil pumped through a heat-exchanger mounted near the bearing. These various types of bearings are fully described in available texts, such as "The Mechanical Engineers' Handbook" (Marks 1951) and "Mechanical Engineers' Handbook" (Kent 1950).

c. Thrust bearing lubrication. The basic principle of operation of all bearing types requires a film of oil between the rotating bearing plate and the babbitted stationary shoes. The rotating parts on some machines are so heavy that when the machine is shut down for a few hours, the oil is squeezed out from between the bearing surfaces and it is necessary to provide means to get oil between the babbitted surface and the bearing plate before the unit is started. Specifications for generators above 10 *MW*, and for generators in unmanned plants, should require provisions for automatically pumping oil under high pressure between the shoes and the runner plate of the thrust bearing just prior to and during machine startup, and when stopping the machine.

d. Guide bearings. A guide bearing is usually provided adjacent to the thrust bearing and is lubricated by the oil in the thrust bearing pot. Except for Kaplan units, machines with guide bearings below the rotor seldom require an upper guide bearing. When the thrust bearing is above the rotor, a lower guide bearing is required. Two guide bearings should always be provided on generators for use with Kaplan turbines. These separate guide bearings have self-contained lubricating systems. Oil in the bearings seldom needs to be cleaned or changed, but when cleaning is necessary, the preferred practice is to completely drain and refill the unit when it is shut down. Valves on oil drains should be of the lock-shield type to minimize possibility of accidental draining of the oil during operation.

3-11. Temperature Devices

a. Types of temperature devices. All generator and turbine bearings are specified to have three temperature sensing devices: a dial-type indicating thermometer with adjustable alarm contacts, embedded resistance temperature detector (RTD) devices, and a temperature relay (Device 38). The dial portions of the indicating thermometers are grouped on a panel which can be part of the governor cabinet, mounted on the generator barrel, or on another panel where they can be easily seen by maintenance personnel or a roving operator.

b. Dial indicator alarms. The dial indicator alarm contacts are set a few degrees above the normal bearing operating temperatures to prevent nuisance alarms. When approaching their alarm setpoint, these contacts tend to bounce and chatter. If they are used with event recorders, they can produce multiple alarms in rapid succession unless some means are used to prevent this.

c. RTDs. RTD leads are brought out to terminal blocks, which are usually mounted in the generator terminal cabinet on the generator air housing. Turbine bearing RTD leads should be terminated in the same place as the generator RTD leads. For bearings equipped with more than one RTD, it is usually adequate to monitor only one, and let the other(s) serve as spares. Thrust bearings may have six or more RTDs. Monitoring three or four of them is usually satisfactory. Generator stator windings usually have several RTDs per phase. On the larger machines, monitor two RTDs per phase, and keep the remainder as spares.

d. RTD monitoring. How the RTDs are used depends partly on the decisions made about the plant control system. They can be scanned by the analog input section of a remote terminal unit (RTU) if the plant is controlled remotely, or they can be used as inputs to a local stand-alone scanner system, with provisions for remote alarms and tripping the unit on high temperatures. In any case, permanent records of bearing temperatures are no longer retained.

e. Control action. Whether to alarm or trip on RTD temperature indication depends on other decisions about how the plant will be controlled, and what kind of control system is used. For automated plants, stator temperature increases can be used as an indication to reduce unit load automatically, for instance.

f. Air temperature indicators. Air temperature indicators in air cooler air streams are used to balance the cooling water flow, and to detect cooler problems. Air temperature alarms should be taken to the control point, or input to the plant control system if the plant is automated.

g. Temperature relays. Temperature relays are typically used to shut the unit down on high bearing temperatures, 105 °C or so. Separate contacts should also be provided for alarming. Note that once a bearing temperature reaches the trip point, the damage has been done. It is almost never possible to save the bearing. Tripping the unit promptly is done to save damage to other parts of the unit resulting from failure of the bearing. Temperature relay alarm points should be taken to the annunciator, and to the RTU or plant control system. It is not necessary to provide sequence of event recording for the Device 38 because the bearing temperature event is such a slow process.

3-12. Final Acceptance Tests

a. General. Because of the size of water wheel generators, they are normally assembled in the field, and because of their custom design, it is advisable to perform a series of acceptance and performance tests on the generators during and following their field assembly. The purpose of these tests is to ensure that the units meet contractual performance guarantees, to provide a quality control check of field assembly work, and finally to provide a "bench mark" of "as-built" conditions serving as an aid in future maintenance and repair activities. Certain field tests are performed on every generator of a serial (multi-unit) purchase; other tests are performed on only one unit of the serial purchase, e.g., tests for ensuring conformance with contractual guarantees.

b. Field acceptance tests and special field tests. These tests are as follows:

(1) Field quality control tests (all units). A series of dielectric and insulation tests for the stator and field windings, performed during field work, including turn-to-turn tests, coil transposition group tests, and semiconducting slot coating-to-stator iron resistance tests, to monitor field assembly techniques.

(2) Field acceptance tests (all units). These tests consist of:

(a) Stator dielectric tests. These tests consist of: Insulation resistance and polarization index, Corona probe test, Corona visibility test, Final AC high potential test, Partial discharge analysis (PDA) test, and Ozone detection (optional).

(b) Rotor dielectric tests.

(c) Stator and rotor resistance tests.

(3) Special field test (one unit of serial). These tests consist of:

(a) Efficiency tests.

(b) Heat run tests.

(c) Machine parameter tests.

(d) Excitation test.

(e) Overspeed tests (optional).

c. Testing considerations.

(1) Planning for tests on the generator after its installation should begin prior to completion of the generator specifications. Any generator that must be assembled in the powerhouse will require field testing after installation to measure values of efficiency and reactances, particularly when efficiency guarantees are included in the purchase specifications. The generator manufacturer performs these tests with a different crew from those employed for generator erection. Specification CW 16120 requires a second generator in the powerhouse with special switching equipment and "back-fed" excitation system to permit performing retardation tests used to determine generator efficiency. In addition, special arrangements are required to use one of the generator-voltage class breakers as a shorting breaker during sudden short-circuit tests.

(2) The manufacturer requires considerable advance notice of desirable testing dates in order to calibrate test instruments and ship in necessary switchgear and excitation equipment. If the associated turbine is to be given a field efficiency test, it may be desirable to coordinate the turbine and generator tests so that the electrical testing instruments will be available to measure generator output during the turbine test. The heat run requires a load on the generator. Normally, the generator is loaded by connecting the generator output to the system load. If system load isn't sufficient to load the generator, IEEE 115 outlines alternative techniques to simulate load conditions.

(3) The testing engineer may elect to use the plant instrument transformers instead of calibrated current and potential transformers if reliable data on plant instrument transformers are available.

(4) Generator erectors usually apply dielectric tests on the armature (stator) and field windings before the rotor is put into the machine. If the stator is wound in the field, a high potential test is usually done once each

day on all of the coils installed during that day. This facilitates repairs if the winding fails under test and may preclude missing scheduled “on-line” dates. The test voltages for these intermediate tests must be planned so that each one has a lower value than the previous test, but greater than the test voltage specified for the final high potential test.

(5) IEEE 43 describes the polarization index test. This index is the ratio of the insulation resistance obtained with a 10-min application of test voltage to that obtained with a similar application for a 1-minute period. Recommended indices and recommended insulation resistance values are also given in the referenced standard.

(b) Because of the relatively small amount of insulation on the field windings, simple insulation (Megger) tests are adequate to determine their readiness for the high-voltage test. Guide Specification CW-16120 requires the dielectric test to be made with the field winding connected to the collector rings and hence the test cannot be made until after the generator is assembled with the DC leads of the static excitation system connected.

3-13. Fire Suppression Systems

Generators with closed air recirculation systems should be provided with automatic carbon dioxide extinguishing systems. See Chapter 15 of EM 1110-2-4205 for details. On larger open ventilated generators, water spray installations with suitable detection systems to prevent false tripping should be considered.

Chapter 4
Power Transformers

4-1. General

a. Type. Step-up transformers for use with main units should be of the oil immersed type for outdoor operation, with a cooling system as described in paragraph 4-3, suited to the location. General Corps of Engineers power transformer design practice is covered by Guide Specification for Civil Works Construction CW-16320.

b. Three-phase transformers. In the majority of applications, three-phase transformers should be used for generator step-up (GSU) applications for the following reasons:

(1) Higher efficiency than three single-phase units of equivalent capacity.

(2) Smaller space requirements.

(3) Lower installed cost.

(4) Lower probability of failure when properly protected by surge arresters, thermal devices, and oil preservation systems.

(5) Lower total weight.

(6) Reduction in weights and dimensions making larger capacities available within practical weight and size limitations.

c. EHV applications. In applications involving interconnection to EHV (345 *kV* and above) systems, reliability and application considerations dictate the use of single-phase units due to lack of satisfactory industry experience with three-phase EHV GSU transformers. The basic switching provisions discussed in Chapter 2 describe the low-voltage switching scheme used with EHV transformers.

d. Transformer features. Regardless of winding configuration, for any given voltage and *kVA* rating, with normal temperature rise, the following features should be analyzed for their effect on transformer life cycle costs:

(1) Type of cooling.

(2) Insulation level of high-voltage winding.

(3) Departure from normal design impedance.

Examples of typical transformer studies which should be performed are contained in Appendix B of this manual.

e. Transformer construction. There are two types of construction used for GSU transformers. These are the core form type and the shell form type. Core form transformers generally are supplied by manufacturers for lower voltage and lower *MVA* ratings. The core form unit is adaptable to a wide range of design parameters, is economical to manufacture, but generally has a low *kVA*-to-weight ratio. Typical HV ranges are 230 *kV* and less and 75 *MVA* and less. Shell form transformers have a high *kVA*-to-weight ratio and find favor on EHV and high *MVA* applications. They have better short-circuit strength characteristics, are less immune to transit damage, but have a more labor-intensive manufacturing process. Both forms of construction are permitted by Corps' transformer guide specifications.

4-2. Rating

The full load *kVA* rating of the step-up transformer should be at least equal to the maximum *kVA* rating of the generator or generators with which they are associated. Where transformers with auxiliary cooling facilities have dual or triple *kVA* ratings, the maximum transformer rating should match the maximum generator rating.

4-3. Cooling

a. General. The standard classes of transformer cool ing systems are listed in Paragraph 5.1, IEEE C57.12.00. Transformers, when located at the powerhouse, should be sited so unrestricted ambient air circulation is allowed. The transformer rating is based on full use of the transformer cooling equipment.

b. Forced cooling. The use of forced-air cooling will increase the continuous self-cooled rating of the transformer 15 percent for transformers rated 2499 *kVA* and below, 25 percent for single-phase transformers rated 2500 to 9999 *kVA* and three-phase transformers rated 2500 to 11999 *kVA*, and 33-1/3 percent for single-phase transformers rated 10000 *kVA* and above and three-phase transformers rated 12000 *kVA* and above. High-velocity fans on the largest size groups will increase the self-cooled rating 66-2/3 percent. Forced-oil cooled transformers, whenever energized, must be operated with the circulating oil pumps operating. Forced-oil transformers with air coolers do not have a self-cooled rating without the air-cooling equipment in operation unless they are special units with a “triple rating.”

c. Temperature considerations. In determining the transformer rating, consideration should be given to the temperature conditions at the point of installation. High ambient temperatures may necessitate increasing the transformer rating in order to keep the winding temperature within permissible limits. If the temperatures will exceed those specified under “Service Conditions” in IEEE C57.12.00, a larger transformer may be required. IEEE C57.92 should be consulted in determining the rating required for overloads and high temperature conditions.

d. Unusual requirements. Class OA/FA and Class FOA meet all the usual requirements for transformers located in hydro plant switchyards. The use of triple-rated transformers such as Class OA/FA/FA is seldom required unless the particular installation services a load with a recurring short time peak.

e. Class FOA transformers. On Class FOA transformers, there are certain considerations regarding static electrification (build-up of charge on the transformer windings due to oil flow). Transformer suppliers require oil pump operation whenever an FOA transformer is energized. Static electrification is important to consider when designing the desired operation of the cooling, and can result in the following cooling considerations:

(1) Decrease in oil flow velocity requirements (for forced-oil cooled units).

(2) Modifying of cooling equipment controls to have pumps come on in stages.

(3) Operation of pumps prior to energizing transformer.

4-4. Electrical Characteristics

a. Voltage.

(1) Voltage ratings and ratios should conform to ANSI C84.1 preferred ratings wherever possible. The high-voltage rating should be suitable for the voltage of the transmission system to which it will be connected, with proper consideration for increases in transmission voltage that may be planned for the near future. In some cases this may warrant the construction of high-voltage windings for series or parallel operation, with bushings for the higher voltage, or windings suitable for the higher voltage tapped for the present operating voltage.

(2) Consideration should also be given to the voltage rating specified for the low-voltage winding. For plants connected to EHV systems, the low-voltage winding rating should match the generator voltage rating to optimally match the generator’s reactive capability in “bucking” the transmission line voltage. For 230-*kV* transmission systems and below, the transformer low-voltage rating should be 5 percent below the generator voltage rating to optimally match the generator’s reactive capability when “boosting” transmission line voltage. IEEE C57.116 and EPRI EL-5036, Volume 2, provide further guidance on considerations in evaluating suitable voltage ratings for the GSU transformer.

b. High-voltage BIL.

(1) Basic Impulse Insulation Levels (BIL) associated with the nominal transmission system voltage are shown in Table 1 of IEEE C57.12.14. With the advent of metal oxide surge arresters, significant economic savings can be made in the procurement of power transformers by specifying reduced BIL levels in conjunction with the application of the appropriate metal oxide arrester for transformer surge protection. To determine appropriate values, an insulation coordination study should be made (see Appendix B for a study example). Studies involve coordinating and determining adequate protective margins for the following transformer insulation characteristics:

(a) Chopped-Wave Withstand (CWW).

(b) Basic Impulse Insulation Level (BIL).

(c) Switching Surge Level (SSL).

(2) If there is reason to believe the transmission system presently operating with solidly grounded neutrals may be equipped with regulating transformers or neutral reactors in the future, the neutral insulation level should be specified to agree with Table 7 of IEEE C57.12.00.

c. Impedance.

(1) Impedance of the transformers has a material effect on system stability, short-circuit currents, and transmission line regulation, and it is usually desirable to keep the impedance at the lower limit of normal impedance design values. Table 4-1 illustrates the range of values available in a normal two-winding transformer design (values shown are for GSU transformers with

Table 4-1
Nominal Design Impedance Limits for Power Transformers Standard Impedance Limits (Percent)

HIGH-VOLTAGE WINDING		AT EQUIV. 55 °C *kVA*			
NOMINAL SYSTEM *kV*	WINDING BIL *kV*	CLASS OA, OR SELF-COOLED RATING OF CLASS OA/FA OR CLASS OA/FA/FA MINIMUM	MAXIMUM	CLASS FOA OR CLASS FOW MINIMUM	MAXIMUM
15	110	5.0	7.5	8.34	12.5
25	150	5.0	7.5	8.34	12.5
34.5	200	5.25	8.0	8.75	14.33
46	250	5.60	8.4	9.34	14.0
69	350	6.1	9.15	10.17	15.25
115	450	5.9	8.85	9.84	14.75
138	550	6.4	9.6	10.67	16.0
161	650	6.9	10.35	11.50	17.25
230	825	7.5	11.25	12.5	18 .75
500	1425	10.95	15.6	18.25	26.0

13.8-*kV* low voltage). Impedances within the limits shown are furnished at no increase in transformer cost. Transformers can be furnished with lower or higher values ofimpedance at an increase in cost. The approximate effect of higher- or lower-than-normal impedances on the cost of transformers is given in Table 4-2. The value of transformer impedance should be determined giving consideration to impacts on selection of the interrupting capacities of station breakers and on the ability of the generators to aid in regulating transmission line voltage. Transformer impedances should be selected based on system and plant fault study results (see Chapter 2). Impedances shown are subject to a tolerance of plus or minus 7.5 percent. (See IEEE C57.12.00).

Table 4-2
Increase In Transformer Cost For Impedances Above and Below The Standard Values

STANDARD IMPEDANCE X	INCREASE IN TRANSFORMER COST
1.45-1.41	3%
1.40-1.36	2%
1.35-1.31	1%
0.90-0.86	2%
0.85-0.81	4%
0.80-0.76	6%

(2) In making comparisons or specifying the value of impedance of transformers, care should be taken to place all transformers on a common basis. Impedance of a transformer is a direct function of its rating, and when a transformer has more than one different rating, it has a different impedance for each rating. For example, to obtain the impedance of a forced-air-cooled transformer at the forced-air-cooled rating when the impedance at its self-cooled rating is given, it is necessary to multiply the impedance for the self-cooled rating by the ratio of the forced-air-cooled rating to the self-cooled rating.

d. Transformer efficiency. Transformer losses represent a considerable economic loss over the life of the power plant. A study should be made to select minimum allowable efficiencies for purposes of bidding. Included in the study should be a determination of the present worth cost of transformer losses. This value is used in evaluating transformer bids that specify efficiency values that exceed the minimum acceptable value. Examples of typical studies are included in Appendix B of this manual. IEEE C57.120 provides further guidance on transformer loss evaluation.

4-5. Terminals

Where low-voltage leads between the transformer and generator are of the metal-enclosed type, it is desirable to extend the lead housing to include the low-voltage terminals of the transformer. This arrangement should be indicated on the specification drawings and included in the specifications in order that the manufacturer will coordinate his transformer top details with the design of the housing. It is sometimes preferable to have the transformer builder furnish the housing over the low-voltage bushings if it simplifies the coordination. All bushing characteristics should conform to the requirements of IEEE C57.19.01. The voltage rating should correspond to the insulation level of the associated winding. Where transformers are installed at elevations of more than 3,300 ft above sea level, bushings of the next higher voltage classification may be required. Bushings for neutral connections should be selected to suit the insulation level of the neutral, as discussed in paragraph 4-4.

4-6. Accessories

a. Oil preservation systems. Three different oil preservation systems are available, as described below. The first two systems are preferred for generator step-up transformers:

(1) Inert gas pressure system. Positive nitrogen gas pressure is maintained in the space between the top of the oil and the tank cover from a cylinder or group of cylinders through a pressure-reducing valve.

(2) Air-cell, constant-pressure, reservoir tank system. A system of one or more oil reservoirs, each containing an air cell arranged to prevent direct contact between the oil and the air.

(3) Sealed tank. Gas is admitted to the space above the oil and the tank is sealed. Expansion tanks for the gas are provided on some sizes. Sealed tank construction is employed for 2,500 *kVA* and smaller sizes.

b. Oil flow alarm. Transformers that depend upon pumped circulation of the oil for cooling should be equipped with devices that can be connected to sound an alarm, to prevent closing of the energizing power circuit, or to deenergize the transformer with loss of oil flow. In forced-oil-cooled units, hot spot detectors should be provided which can be connected to unload the transformer if the temperature exceeds that at which the second oil pump is expected to cut in. FOA transformers should employ control schemes to ensure pump operation prior to energizing the transformer.

c. Surge arresters. Surge arresters are located near the transformer terminals to provide protection of the high-voltage windings. Normal practice is to provide brackets on the transformer case (230-*kV* HV and below) for mounting the selected surge arrester.

d. Fans and pumps. The axial-flow fans provided for supplementary cooling on Class OA/FA transformers are equipped with special motors standardized for 115-V and 230-V single-phase or 208-V three-phase operation. Likewise, oil circulating pumps for FOA transformers are set up for single-phase AC service. Standard Corps of Engineers practice is to supply 480-V, three-phase power to the transformer and have the transformer manufacturer provide necessary conversion equipment.

e. On-line dissolved gas monitoring system. The detection of certain gases, generated in an oil-filled transformer in service, is frequently the first available indication of possible malfunction that may eventually lead to the transformer failure if not corrected. The monitoring system can provide gas analysis of certain gases from gas spaces of a transformer. The system output contacts can be connected for an alarm or to unload the transformer if the gas levels exceed a set point. The type of gases generated, during the abnormal transformer conditions, is described in IEEE C57.104.

f. Temperature detectors. A dial-type temperature indicating device with adjustable alarm contacts should be provided for oil temperature indication. Winding RTDs should be provided, and monitored by the plant control system or a stand-alone temperature recorder, if one is provided for the generator and turbine RTDs. At least two RTDs in each winding should be provided.

g. Lifting devices. If powerhouse cranes are to be used for transformer handling, the manufacturer's design of the lifting equipment should be carefully coordinated with the crane clearance and with the dimensions of the crane hooks. The lifting equipment should safely clear bushings when handling the completely assembled transformer, and should be properly designed to compensate for eccentric weight dispositions of the complete transformer with bushings.

h. On-line monitoring systems. In addition to the on-line dissolved gas monitoring system described in paragraph 4-6*e*, other on-line systems are available to monitor abnormal transformer conditions. These include:

(1) Partial discharge analysis.

(2) Acoustical monitoring.

(3) Fiber-optic winding temperature monitoring.

(4) Bearing wear sensor (forced-oil-cooled units).

(5) Load tap changer monitor (if load tap changers are used).

Early detection of the potential for a condition leading to a forced outage of a critical transformer bank could more than offset the high initial costs of these transformer accessories by avoiding a more costly loss of generation.

i. Dial-type indicating devices. Dial-type indicating devices should be provided for:

(1) Liquid level indication.

(2) Liquid temperature indicator.

(3) Oil flow indicators (see paragraph 4-6*b*).

These are in addition to the dial-type indicators that are part of the winding temperature systems (see paragraph 4-6*f*).

4-7. Oil Containment Systems

If any oil-filled transformers are used in the power plant, provisions are made to contain any oil leakage or spillage resulting from a ruptured tank or a broken drain valve. The volume of the containment should be sufficient to retain all of the oil in the transformer to prevent spillage into waterways or contamination of soil around the transformer foundations. Special provisions (oil-water separators, oil traps, etc.) must be made to allow for separation of oil spillage versus normal water runoff from storms, etc. IEEE 979 and 980 provide guidance on design considerations for oil containment systems.

4-8. Fire Suppression Systems

a. General. Fire suppression measures and protective equipment should be used if the plant's oil-filled transformers are located in close proximity to adjacent transformers, plant equipment, or power plant structures. Oil-filled transformers contain the largest amount of combustible material in the power plant and so require due consideration of their location and the use of fire suppression measures. Fires in transformers are caused primarily from breakdown of their insulation systems, although bushing failures and surge arrester failures can also be causes. With failure of the transformer's insulation system, internal arcing follows, creating rapid internal tank pressures and possible tank rupture. With a tank rupture, a large volume of burning oil may be expelled over a large area, creating the possibility of an intense fire.

b. Suppression measures. Suppression measures include the use of fire quenching pits or sumps filled with coarse rock surrounding the transformer foundation and physical separation of the transformer from adjacent equipment or structures. Physical separation in distance is also augmented by the use of fire-rated barriers or by fire-rated building wall construction when installation prevents maintaining minimum recommended separations. Economical plant arrangements generally result in less than recommended minimums between transformers and adjacent structures so water deluge systems are supplied as a fire prevention and suppression technique. The systems should be of the dry pipe type (to prevent freeze-up in cold weather) with the system deluge valves actuated either by thermostats, by manual break-glass stations near the transformer installation, or by the transformer differential protective relay.

Chapter 5
High-Voltage System

5-1. Definition

The high-voltage system as treated in this chapter includes all equipment and conductors that carry current at transmission line-voltage, with their insulators, supports, switching equipment, and protective devices. The system begins with the high-voltage terminals of the step-up power transformers and extends to the point where transmission lines are attached to the switchyard structure. High-voltage systems include those systems operating at 69 *kV* and above, although 34.5-*kV* and 46-*kV* systems that are subtransmission-voltage systems are also covered in this chapter. Transmission line corridors from the powerhouse to the switchyard should allow adequate clearance for maintenance equipment access, and clear working space. Working clearances shall be in accordance with the applicable sections of ANSI C2, Part 2.

5-2. Switchyard

a. Space around the switchyard. Adequate space should be allowed to provide for extension of the switchyard facilities when generating units or transmission lines are added in the future. The immediate surroundings should permit the building of lines to the switchyard area from at least one direction without the need for heavy dead-end structures in the yard.

b. Switchyard location. Subject to these criteria, the switchyard should be sited as near to the powerhouse as space permits, in order to minimize the length of control circuits and power feeders and also to enable use of service facilities located in the powerhouse.

c. Switchyard fencing. A chain link woven wire fence not less than 7 ft high and topped with three strands of barbed wire slanting outward at a 45-deg angle, or concertina wire, with lockable gates, should be provided to enclose the entire yard. Other security considerations are discussed in EM 1110-2-3001.

5-3. Switching Scheme

The type of high-voltage switching scheme should be selected after a careful study of the flexibility and protection needed in the station for the initial installation, and also when the station is developed to its probable maximum capacity. A detailed discussion of the advantages and disadvantages of various high-voltage switching schemes is included in this chapter.

a. Minimum requirements. The initial installation may require only the connecting of a single transformer bank to a single transmission line. In this case, one circuit breaker, one set of disconnects with grounding blades, and one bypass disconnecting switch should be adequate. The high-voltage circuit breaker may even be omitted under some conditions. The receiving utility generally establishes the system criteria that will dictate the need for a high side breaker.

b. Bus structure. When another powerhouse unit or transmission line is added, some form of bus structure will be required. The original bus structure should be designed with the possibility of becoming a part of the ultimate arrangement. Better known arrangements are the main and transfer bus scheme, the ring bus scheme, the breaker-and-a-half scheme, and the double bus-double breaker scheme.

c. Main and transfer bus scheme.

(1) The main and transfer bus scheme, Figure 5a, consists of two independent buses, one of which is normally energized. Under normal conditions, all circuits are tied to the main bus. The transfer bus is used to provide service through the transfer bus tie breaker when it becomes necessary to remove a breaker from service.

(2) Advantages of the main and transfer bus arrangement include:

(a) Continuity of service and protection during breaker maintenance.

(b) Ease of expansion.

(c) Small land area requirements.

(d) Low cost.

(3) Disadvantages include:

(a) Breaker failure or bus fault causes the loss of the entire station.

(b) Bus tie breaker must have protection schemes to be able to substitute for all line breakers.

(c) An additional tie breaker is required.

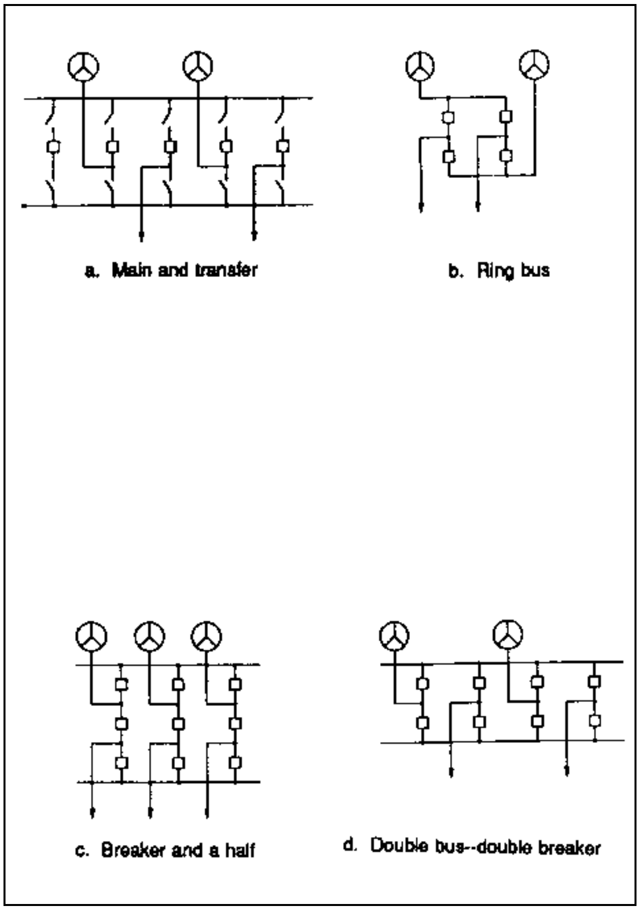

Figure 5-1. Switchyard bus arrangements

d. Ring bus scheme.

(1) The ring bus, Figure 5-1b, consists of a loop of bus work with each bus section separated by a breaker. Only limited bus sections and circuits can be removed from service in the event of a line or bus fault. A line fault results in the loss of the breakers on each side of the line, while a breaker failure will result in the removal of two bus sections from service. The ring bus arrangement allows for circuit breaker maintenance without interruption of service to any circuit.

(2) The advantages of the ring bus scheme include:

(a) Low cost (one breaker per line section).

(b) High reliability and operational flexibility.

(c) Continuity of service during breaker and bus maintenance.

(d) Double feed to each circuit.

(e) Expandable to breaker-and-a-half scheme.

(3) Disadvantages include:

(a) Each circuit must have its own potential source.

(b) Usually limited to four circuits.

e. Breaker-and-a-half scheme.

(1) The breaker-and-a-half arrangement, Figure 5-1c, provides for two main buses, both normally energized. Between the buses are three circuit breakers and two circuits. This arrangement allows for breaker maintenance without interruption of service. A fault on either bus will cause no circuit interruption. A breaker failure results in the loss of two circuits if a common breaker fails and only one circuit if an outside breaker fails.

(2) The advantages of the breaker-and-a-half scheme include:

(a) High reliability and operational flexibility.

(b) Capability of isolating any circuit breaker or either main bus for maintenance without service interruption.

(c) A bus fault does not interrupt service.

(d) Double feed to each circuit.

(e) All switching can be done with circuit breakers.

(3) The disadvantages include:

(a) Added cost of one half breaker for each circuit.

(b) Protection and control schemes are more complex.

f. Double bus-double breaker scheme.

(1) The double bus-double breaker arrangement, Figure 5-1d, consists of two main buses, both normally energized. Between the main buses are two breakers and one circuit. This arrangement allows for any breaker to be removed from service without interruption to service to its circuit. A fault on either main bus will cause no circuit outage. A breaker failure will result in the loss of only one circuit.

(2) The advantages of the double bus-double breaker scheme include:

(a) Very high reliability and operational flexibility.

(b) Any breaker or either bus can be isolated without service interruption.

(c) A bus fault does not interrupt service.

(d) There is a double feed to each circuit.

(e) All switching is done with circuit breakers.

(f) Only one circuit is lost if a breaker fails.

(3) The disadvantages include the high cost of two breakers per circuit.

g. Recommended scheme. The breaker-and-a-half scheme is generally recommended, as it provides flexibility and a reasonably simple method of providing full relay protection under emergency switching conditions. The number of sections (line "bays") needed is dependent on the number of transmission lines and generation sources coming into the substation. The breaker-and-a-half scheme is normally designed and operated as a ring bus until system requirements dictate more than six breakers and six lines.

5-4. Bus Structures

a. Arrangements. The flat or low profile type of bus construction with pedestal-supported rigid buses and A-frame line towers is ordinarily the most economical where space and topography are favorable. Congested areas may require the use of a high, narrow steel structure and the use of short wire bus connections between disconnecting switches and the buses. Switchyard layouts should provide adequate access for safe movement of maintenance equipment and the moving of future circuit breakers or other major items of equipment into position without de-energizing primary buses. Clearances to energized parts should, as a minimum, comply with ANSI C2, Section 12. Equipment access requirements should be based on the removal of high-voltage bushings, arresters, and conservators and radiators from large power transformers.

b. Bus design criteria. The design of rigid bus systems is influenced by the following criteria:

(1) Electrical considerations including corona and ampacity limitations.

(2) Structural considerations including ice and wind loading, short-circuit forces, and seismic loads.

The spacing of bus supports should limit bus sag under maximum loading to not greater than the diameter of the bus, or 1/150th of the span length. IEEE 605 provides further information on substation electrical, mechanical, and structural design considerations.

5-5. Switchyard Materials

a. General. After design drawings showing a general layout of the switchyard and details of electrical interconnections have been prepared, a drawing should be made up to accompany the specifications for the purchase of the structures. This drawing should show the size, spacing, and location of principal members and the loadings imposed by electrical equipment and lines. Design load assumptions for bus structures are described in EM 1110-2-3001.

b. Structure materials. The following are four types of material most commonly used for substation structures:

(1) Steel. Steel is the most commonly used material. Its availability and good structural characteristics make it economically attractive. Steel, however, must have adequate corrosion protection such as galvanizing or painting. Due to the maintenance associated with painting, galvanizing is generally preferred. Galvanized steel has an excellent service record in environments where the pH level is in the range of 5.4 through 9.6 (i.e., a slightly alkaline environment). Most industrial environments are in this pH range leading to the widespread use and excellent service record of galvanized steel structures. Because of the unbroken protective finish required, structures should not be designed to require field welding or drilling. Adequate information to locate mounting holes, brackets, and other devices must be provided to the fabricator to allow all detail work to be completed before the protective finish is applied to the steel part.

(2) Aluminum. In environments where the pH level is below 5.4 (i.e. an acidic environment, such as conditions existing in a brine mist), galvanized structures would give poor service. In these environments, consideration should be given to structures fabricated with aluminum members. Aluminum structures are satisfactory at other locations, if the installed cost is comparable to the cost of the equivalent design using galvanized steel members. Structures designed for aluminum are constructed of Alloy 6061-T6 and should be designed, fabricated, and erected

in accordance with the Aluminum Association's specifications for aluminum structures.

(3) Concrete. Pre-cast, pre-stressed concrete structures may be economical in some applications such as pull-off poles and switch structures. Care should be taken to avoid the use of detrimental additives, such as calcium chloride, to the concrete used in the structures. Due to the larger structural sizes and weights involved, special equipment may be required for concrete erection.

(4) Wood. Wood pole and timber structures may be economical for temporary structures or simple switch structures. Wood members must be treated with an appropriate preservative. Structural properties and size tolerances of wood are variable and must be considered during the design process.

c. Bus materials. The materials most commonly used for rigid and wire bus are aluminum and copper. Rigid bus fittings should be limited to bolted connections for copper, and welded connections on aluminum. Bus fittings for aluminum wire should be compression type. Either bolted or compression fittings are acceptable for use with copper wire bus.

5-6. Transformer Leads

a. High-voltage terminal connections. The connections between the high-voltage terminals of the transformer and the disconnect switch (or breaker) will usually be made with bare overhead conductors when the transformer is located in the switchyard. However, in cases where the transformer is in line with the axis of the disconnect, the connection between the disconnect terminals and the high-voltage bushing terminals can be made with suitably supported and formed rigid bus of the same type used in the rest of the switchyard. The fittings and interconnection systems between the high-voltage bus and the disconnect switches should be designed to accommodate conditions of frequent load cycling and minimal maintenance.

b. Overhead conductors. Bare overhead conductors from the transmission line termination to the high-voltage bushings can occasionally be used when the transformers are installed at the powerhouse, and overhead lines to the switchyard are used. An example of this would be when the transmission line is dead-ended to the face of the dam, and the transformer is located at the base of the dam near its face, and behind the powerhouse. However, locating the transformers at the powerhouse usually requires the use of high-voltage bus to the line termination when the line is terminated on a dead-end structure near the transformer.

c. Test terminals. To provide a safe and accurate method of transformer dielectric testing, accommodations should be made for easily isolating transformer bushings from the bus work. Double test terminals should be provided on transformer high-voltage and neutral bushings in accordance with Corps of Engineers practice. The design should provide adequate clearance from energized lines for personnel conducting the tests.

5-7. Powerhouse - Switchyard Power Control and Signal Leads

a. Cable tunnel.

(1) A tunnel for power and control cables should be provided between the powerhouse and switchyard whenever practical. Use of a tunnel provides ready access to the cables, provides for easy maintenance and expansion, and offers the easiest access for inspection. This tunnel should extend practically the full length of the switchyard for access to all of the switchyard equipment.

(2) The control and data (non-signal) cables should be carried in trays in the tunnel, and continued in steel conduits from the trays to circuit breakers and other controlled equipment so as to eliminate the need for manholes and handholes. If there is a control house in the switchyard, it should be situated over the tunnel. The tunnel should be lighted and ventilated and provided with suitable drains, or sumps and pumps.

(3) If the generator leads, transformer leads, or station service feeders are located in the tunnel, the amount of heat dissipated should be calculated and taken into consideration in providing tunnel ventilation. The power cables should be carefully segregated from the control and data acquisition cables to prevent electromagnetic interference, and to protect the other cables from damage resulting from power cable faults. If the tunnel lies below a possible high-water elevation, it should be designed to withstand uplift pressures.

(4) Signal cables should be physically separated from power and control circuits. If practical, the signal cable should be placed in cable trays separate from those used for either control or power cables. In no case should signal cables be run in conduit with either control or power cables. The physical separation is intended to reduce the coupling of electromagnetic interference into the signal cable from pulses in the (usually unshielded)

control cables, or power system frequency energy from power cables. Even though the signal cable will be shielded, commercially available shielding does not provide 100 percent coverage or perfect shielding, and the separation is needed to reduce electrical noise superimposed on the signal.

b. Duct line. For small installations having a limited amount of transforming and switching equipment, it may be desirable and economical to use duct lines instead of a cable tunnel for control and power cables. The duct system should use concrete encased nonmetallic conduit, and manholes or handholes of adequate number and size should be provided. Separate ducts for the power cables and the control and data acquisition cables should be provided. At least 30 percent spare duct capacity should be provided for power cables, and 50 percent spare capacity provided for control and data acquisition cables. The manholes should be designed to drain unless costs are prohibitive.

c. High-voltage bus.

(1) General. There are three categories of high-voltage connection systems that find application in hydroelectric installations requiring high-voltage interconnection between the power plant and the switchyard or utility grid interconnection. These are as follows:

(a) Oil or SF_6 gas-insulated cable with paper-insulated conductors. Cables commonly used for circuits above 69 *kV* consist of paper-insulated conductors pulled into a welded steel pipeline, which is filled with insulating oil or inert gas. The oil or gas in the pipe type construction is usually kept under about 200 psi pressure. These cables can safely be installed in the same tunnel between the powerhouse and the switchyard that is used for control cables.

(b) Solid dielectric-insulated cable. Solid dielectric-insulated cables are also available for systems above 69 *kV*. Their use may be considered, but careful evaluation of their reliability and performance record should be made. They offer advantages of ease of installation, elimination of oil or gas system maintenance, and lower cost. Their electrical characteristics should be considered in fault studies and stability studies.

(c) SF_6 gas-insulated bus. An example of a typical installation is an underground power plant with a unit switching scheme and the GSU transformer located underground in the plant. A high-voltage interconnection is required through a cable shaft or tunnel to an above-ground on-site switchyard.

(2) Direct burial. While insulated cable of the type described can be directly buried, the practice is not recommended for hydroelectric plants because the incremental cost of a tunnel normally provided for control circuits and pipelines is moderate. In case of oil leaks or cable failure, the accessibility of the cable pipes in the tunnel will speed repairs and could avoid considerable loss in revenue. Space for the location of cable terminal equipment should be carefully planned.

(3) Burial trench. If the power cables from the powerhouse to the switchyard must be buried directly in the earth, the burial trench must be in accordance with safety requirements, provide a firm, conforming base to lay the cable on, and provide protection over the cable. The cable must have an overall shield, which must be well-grounded, to protect, so far as possible, people who might accidently penetrate the cable while digging in the burial area.

(4) SF_6 gas-insulated systems. SF_6 gas-insulated systems offer the possibility of insulated bus and complete high-voltage switchyard systems in a compact space. Gas-insulated substation systems should be considered for underground power plant installations or any situation requiring a substation system in an extremely confined space. The design should accommodate the need for disassembly of each part of the system for maintenance or repair. The designer should also consider that the gas is inert, and in a confined space will displace oxygen and cause suffocation. After exposure to arcing, SF_6 gas contains hazardous byproducts and special precautions are needed for evacuating the gas and making the equipment safe for normal maintenance work. SF_6 gas pressure varies with temperature and will condense at low ambient temperatures. When SF_6 equipment is exposed to low temperatures, heating must be provided. The manufacturer's recommendations must be followed. IEEE C37.123 provides guidance on application criteria for gas insulated substation systems.

5-8. Circuit Breakers

a. Interrupting capacity. The required interrupting rating of the circuit breakers is determined by short-circuit fault studies. (See Chapter 2.) In conducting the studies, conservative allowances should be made to accommodate ultimate system growth. If information of system capacity and characteristics is lacking, an infinite bus at the end of the transmission interconnection can be assumed. Using an infinite bus will result in conservative values of fault *kVA* to be interrupted, and will probably not unduly influence the final result. ANSI C37.06 provides performance parameters of standard high-voltage breakers.

b. Design considerations.

(1) Breakers for 69 *kV* and above generally are SF_6 gas-insulated, with the dead tank design preferred for seismic considerations. The details of the relaying will determine the number of CTs required, but two CTs per pole should generally be the minimum. Three CTs may be required for the more complex switching arrangements, such as the breaker-and-a-half scheme.

(2) At 230 *kV* and above, two trip coils are preferred. The integrity of the tripping circuit(s) should be monitored and if remotely controlled, the status should be telemetered to the control point. The gas system of SF_6 breakers should be monitored since loss of SF_6 gas or low gas pressure blocks breaker operation.

(3) Breaker auxiliary “a” and “b” switch contacts are used extensively to initiate and block the operation of backup relaying schemes. As breakers are added, and protection added to cover new system contingencies, the protective relay schemes become more complex. To accommodate these situations, breakers should be purchased with at least eight “a” and eight “b” spare auxiliary contacts.

(4) Layout of the substation should consider access required for maintenance equipment, as well as horizontal and vertical electrical clearance for the switches in all normal operating positions.

(5) Specifications prepared for outdoor applications of SF_6 power circuit breakers should provide the expected ambient operating temperature ranges so the breaker manufacturer can provide adequate heating to ensure proper operation of the breaker through the ambient operating range. Minimum standard operating ambient for SF_6 equipment is -30 °C (IEEE Standard C37.122).

5-9. Disconnect Switches

a. Disconnect operators. Manual or motor-operated gang-operated disconnect switches should be provided for isolating all circuit breakers. For operating voltages of 230 *kV* or greater, or for remotely operated disconnects, the disconnects should be motor operated. In some cases, depending on the switching scheme and substation layout, one or both of the buses will be sectionalized by disconnects. The sectionalizing disconnect switches may be either manual or motor-operated, depending on their voltage rating and the requirements of station design. The manual operating mechanism for heavy, high-voltage disconnects should preferably be of the worm gear, crank-operated type.

b. Remotely operated disconnects. Remotely operated disconnect switches should be installed only as line or breaker disconnects. Use of a remotely operated disconnect switch to serve as generator disconnect is strongly discouraged. Operation of generator disconnects should require visual verification (through operator presence) of the open position and a lockable open position to prevent the possibility of misoperation or misindication by reconnecting an out-of-service generator to an energized line.

c. Disconnect features. All disconnect switches should be equipped with arcing horns. The disconnect switch on the line side of the line circuit breakers should be equipped with grounding blades and mechanically interlocked operating gear. At 230 *kV* and above, line and generator disconnect switches should be of the rotating insulator, vertical break type, with medium- or high-pressure contacts. Circuit breaker isolation switches may be either a two-insulator “V” or a side break type. Both the contacts and the blade hinge mechanism should be designed and tested to operate satisfactorily under severe ice conditions. At 345 *kV* and 500 *kV*, vertical break disconnects are preferred since they allow for reduced phase spacing and installation of surge suppression resistors. Each switch pole should have a separate motor operator.

5-10. Surge Arresters

a. Preferred arrester types. Surge arresters should be of the station type (preferably a metal oxide type) that provides the greatest protective margins to generating station equipment.

b. Arrester location. Arresters should be located immediately adjacent to the transformers, if the connection between the transformers and switching equipment is made by overhead lines. If high-voltage cable is used for this connection, the arresters should be placed both near the switchyard terminals of the cable and adjacent to the transformer terminals. Arrester connections should be designed to accommodate removal of the arrester without removing the main bus connection to the high-voltage bushing. Location of arresters should be in accordance with IEEE C62.2.

c. Arrester protection. In all cases, enough space should be allowed between arresters and other equipment to prevent damage if the arresters should fail. If arresters are located where they form a hazard to operating personnel, they should be suitably enclosed. This can generally be accomplished with a woven wire fence provided with a lockable gate. The design of the enclosure should consider the clearance requirements for the switchyard operating voltage.

d. Arrester voltage rating. The voltage rating of the arresters should be selected to provide a reasonable margin between the breakdown voltage of the arrester and the basic impulse insulation level (BIL) of the equipment protected. The rating, in the majority of cases, should be the lowest satisfactory voltage for the system to which the arresters are connected.

e. Grounded-neutral arresters.

(1) In applying grounded-neutral rated arresters, the designer should consider whether, under all conditions of operation, the system characteristics will permit their use. Grounded-neutral arresters should not be used unless one of the following conditions will exist:

(a) The system neutral will be connected to the system ground through a copper grounding conductor of adequate size (solidly grounded) at every source of supply of short-circuit current.

(b) The system neutral is solidly grounded or is grounded through reactors at a sufficient number of the sources of supply of short-circuit current so the ratio of the fundamental-frequency zero-sequence reactance, X_o, to the positive sequence reactance, X_1, as viewed from the point of fault, lies between values of 0 and 3.0 for a ground fault to any location in the system, and for any condition of operation. The ratio of the zero-sequence resistance, R_o, to the positive sequence reactance, X_1, as viewed from the ground fault at any location, should be less than 1.0. The arrester should have suitable characteristics so that it will not discharge during voltage rises caused by switching surges or fault conditions.

(2) Consideration should be given to the protection of transmission line equipment that may be located between the arresters and the incoming transmission line entrance to the substation. In cases where the amount of equipment is extensive or the distance is substantial, it will probably be desirable to provide additional protection on the incoming transmission line, such as spark gaps or arresters.

(3) If the station transformers are constructed with the high-voltage neutral connection terminated on an external (H_0) bushing, a surge arrester should be applied to the bushing.

Chapter 6
Generator-Voltage System

6-1. General

The generator-voltage system described in this chapter includes the leads and associated equipment between the generator terminals and the low-voltage terminals of the GSU transformers, and between the neutral leads of the generator and the power plant grounding system. The equipment generally associated with the generator-voltage system includes switchgear; instrument transformers for metering, relaying, and generator excitation systems; neutral grounding equipment; and surge protection equipment. The equipment is classified as medium-voltage equipment.

6-2. Generator Leads

a. General. The term “generator leads” applies to the circuits between the generator terminals and the low-voltage terminals of the GSU transformers. The equipment selected depends upon the distance between the generator and transformer, the capacity of the generator, the type of generator breakers employed, and the economics of the installation. There are two general classes of generator leads: those consisting of metal-enclosed buses and those consisting of medium-voltage cables. The two classes, their advantages, disadvantages, and selection criteria are discussed in the following subparagraphs.

b. Metal-enclosed buses. There are three categories of metal-enclosed bus: nonsegregated-phase, segregated-phase, and isolated-phase. Each type has specific applications dependent mainly on current rating and type of circuit breaker employed with the bus.

(1) Nonsegregated-phase buses. All phase conductors are enclosed in a common metal enclosure without barriers, with phase conductors insulated with molded material and supported on molded material or porcelain insulators. This bus arrangement is normally used with metal-clad switchgear and is available in ratings up to 4,000 A (6,000 A in 15-*kV* applications) in medium-voltage switchgear applications.

(2) Segregated-phase buses. All phase conductors are enclosed in a common enclosure, but are segregated by metal barriers between phases. Conductor supports usually are of porcelain. This bus arrangement is available in the same voltage and current ratings as nonsegregated-phase bus, but finds application where space limitations prevent the use of isolated-phase bus or where higher momentary current ratings than those provided by the nonsegregated phase are required.

(3) Isolated-phase buses. Each phase conductor is enclosed by an individual metal housing, which is separated from adjacent conductor housings by an air space. Conductor supports are usually of porcelain. Bus systems are available in both continuous and noncontinuous housing design. Continuous designs provide an electrically continuous housing, thereby controlling external magnetic flux. Noncontinuous designs provide external magnetic flux control by insulating adjacent sections, providing grounding at one point only for each section of the bus, and by providing shorting bands on external supporting steel structures. Noncontinuous designs can be considered if installation of the bus will be at a location where competent field welders are not available. However, continuous housing bus is recommended because of the difficulty in maintaining insulation integrity of the noncontinuous housing design during its service life. Isolated-phase bus is available in ratings through 24,000 A and is associated with installations using station cubicle switchgear (see discussion in paragraph 6-7*b*).

c. Metal-enclosed bus application criteria.

(1) For most main unit applications, the metal-enclosed form of generator leads is usually preferred, with preference for the isolated-phase type for ratings above 3,000 A. Enclosed buses that pass through walls or floors should be arranged so as to permit the removal of housings to inspect or replace insulators.

(2) On isolated-phase bus runs (termed “delta bus”) from the generators to a bank of single-phase GSU transformers, layouts should be arranged to use the most economical combination of bus ratings and lengths of single-phase bus runs. The runs (“risers”) to the single-phase transformers should be sized to carry the current corresponding to the maximum *kVA* rating of the transformer.

(3) Metal-enclosed bus connections to the GSU transformer that must be supported at the point of connection to the transformer should have accommodations permitting the bus to be easily disconnected should the transformer be removed from service. The bus design should incorporate weather-tight closures at the point of disconnection to prevent moisture from entering the interior of the bus housing.

(4) On all enclosed bus runs, requirements for enclosing the connections between the bus and the low-voltage bushings of the GSU transformer should be coordinated and responsibilities for scopes of supply clearly defined between transformer supplier and bus supplier. Details of the proposed design of the connector between the GSU transformer bushing terminals and the bus terminal should be evaluated to ensure probability of reliable service life of the connection system.

d. Insulated cables.

(1) Cables may be appropriate for some small generators or in installations where the GSU transformer is located in the plant's switchyard. In the latter situation, economic and technical evaluations should be made to determine the most practical and cost-effective method to make the interconnection. Cables, if used, should have copper conductors. Acceptable cable types include:

(a) Single conductor, ethylene-propylene-rubber (EPR) insulated, with non-PVC jacket.

(b) Multi-conductor, ethylene-propylene-rubber (EPR) insulated cables, with aluminum or steel sheath, and non-PVC jacket, in multiple if necessary to obtain capacity.

(c) Oil-pipe cable systems.

(2) Oil-filled cable terminations with cables terminated with a conductor lug and a stress cone should be used for terminating oil-pipe cable systems. Cold shrink termination kits should be used for terminating single and multi-conductor EPR cables. Termination devices and kits should meet the requirements of IEEE 48 for Class I terminations.

(3) When cables of any type are run in a tunnel, the effect of cable losses should be investigated to determine the safe current-carrying capacity of the cable and the extent of tunnel ventilation required to dissipate the heat generated by these losses. Locations where hot spots may occur, such as risers from the tunnel to equipment or conduit exposed to the sun, should be given full consideration.

6-3. Neutral Grounding Equipment

Equipment between the generator neutral and ground should, insofar as practicable, be procured along with the generator main leads and switchgear. The conductor may be either metal-enclosed bus or insulated cable in non-magnetic conduit. Generator characteristics and system requirements determine whether the machine is to be solidly grounded through a circuit breaker (usually not possible), through a circuit breaker and reactor (or resistor), or through a disconnecting switch and a distribution type of transformer (See Chapter 3.) Solidly grounded systems do not find wide application because resulting fault currents initiated by a stator to ground fault are much higher than currents produced by alternative neutral grounding systems. Higher ground fault currents lead to higher probability of damage to the stator laminations of the connected generator. If a circuit breaker is used in the grounding scheme, it can be either a single-pole or a standard 3-pole air circuit breaker with poles paralleled to form a single-pole unit. Suitable metal enclosures should be provided for the reactors, resistors, or grounding transformers used in the grounding system.

6-4. Instrument Transformers

a. General. The instrument transformers required for the unit control and protective relaying are included in procurements for metal-clad switchgear breakers that are to be employed for generator switching. The instrument transformers are mounted in the switchgear line-up with potential transformers mounted in draw-out compartments for maintenance and service. Current transformers for the GSU transformer zone differential relay are also mounted in the metal-clad switchgear cubicles. In isolated-phase bus installations, the instrument transformers are included in procurement for the isolated-phase bus. The current transformers, including those for generator differential and transformer differential protection, are mounted "in-line" in the bus with terminations in external terminal compartments. Required potential transformers are mounted in dedicated compartments tapped off the main bus leads. The dedicated compartments also contain the generator surge protection equipment (see Chapter 3, "Generators"). Specified accuracy classes for instrument transformers for either type of procurement should be coordinated with the requirements of the control, protective relaying, and metering systems. Instrument transformers for the generator excitation system should be included in the appropriate procurement.

b. Current transformers. Current transformers of the multiple secondary type are usually required and are mounted in the isolated-phase bus or in the metal-clad switchgear to obtain the necessary secondary circuits within a reasonable space. Current transformers in the neutral end of the generator windings are usually mounted in the generator air housing. Accessibility for short-circuiting the secondary circuits should be considered in the equipment layout. The current transformers should be designed to withstand the momentary currents and short-circuit stresses for which the bus or switchgear is rated.

c. Potential transformers. The potential transformers for metering and for excitation system service are housed in separate compartments of the metal-clad switchgear. If station cubicle breakers or isolated-phase bus are involved, a special cubicle for potential transformers and surge protection equipment is provided in a variety of arrangements to simplify generator lead connections. Potential transformers should be protected by current-limiting resistors and fuses. Draw-out type mountings are standard equipment in metal-clad switchgear. Similar arrangements are provided in cubicles associated with isolated-phase bus. Cubicles with the isolated-phase buses also provide phase isolation for transformers.

6-5. Single Unit and Small Power Plant Considerations

When metal-clad switchgear is used for generators in small plants (having typically one or two generators of approximately 40,000 *kW* or less) the switchgear may be equipped with indicating instruments, control switches, and other unit control equipment (e.g., annunciators and recorders) mounted on the switchgear cell doors. This arrangement can take the place of a large portion of the conventional control switchboard. The switchgear may be located in a control room, or the control room omitted entirely, depending upon the layout of the plant. Current philosophy is to make the smaller plants suitable for unmanned operation, and remote or automatic control. This scheme eliminates the need for a control room. Arrangements for control equipment with this type of scheme are described in more detail in Chapter 8, "Control System."

6-6. Excitation System Power Potential Transformer

The power potential transformer (PPT) is fed from the generator leads as described in paragraph 3-6*e*(2), Chapter 3, "Generators." The PPT is procured as part of the excitation system equipment. The PPT should be a three-phase, 60-Hz, self-cooled, ventilated dry type transformer. The PPT is generally tapped at the generator bus with primary current limiting fuses, designed for floor mounting, and with a low-voltage terminal chamber with provisions for terminating the bus or cable from the excitation system power conversion equipment.

6-7. Circuit Breakers

a. General. The particular switching scheme selected from those described in Chapter 2, "Basic Switching Provisions," the generator voltage and capacity rating, and results from fault studies will determine the type of generator breaker used for switching, together with its continuous current rating and short-circuit current rating. If a "unit" switching scheme is chosen with switching on the high side of the GSU transformer, then criteria regarding high-voltage power circuit breakers as described in Chapter 5, "High-Voltage System" are used to select an appropriate breaker. If a generator-voltage switching scheme is selected, then criteria outlined in this paragraph should be used for breaker selection.

b. Generator-voltage circuit breaker types.

(1) When generator-voltage circuit breakers are required, they are furnished in factory-built steel enclosures in one of three types. Each type of circuit breaker has specific applications dependent on current ratings and short-circuit current ratings. In general, Table 6-1 provides a broad overview of each breaker type and its range of application for generator switching. The three types are as follows:

(a) Metal-clad switchgear. Metal-clad switchgear breakers can be used for generator switching on units of up to 45 *MVA* at 13.8 *kV*, depending on interrupting duty requirements. Details of construction are covered in Guide Specification for Civil Works Construction CWGS-16345. Either vacuum interrupters or SF_6 interrupting mediums are permitted by the guide specification.

(b) Station-type cubicle switchgear. Station-type breakers can be used in generator switching applications on units of approximately 140 *MVA*. Details of construction are covered in IEEE C37.20.2. For SF_6 circuit breakers, the insulating and arc-extinguishing medium is the gas. For indoor equipment, in areas not allowed to reach temperatures at or near freezing, the gas will probably not require heating provisions. However, special care and handling is needed for SF_6 gas.

(c) In-line isolated-phase bus breakers. For high-current, medium-voltage, generator breaker applications, i.e., 15 *kV*, 6,000 Amp or higher, in-line breakers mounted in the isolated-phase bus system have been employed on high-capacity systems. These breakers

Table 6-1
Generator Breaker Application Table, 13.8-*kV* Application

Upper Limit Generator Application MVA	Continuous Current Rating, kA	Short-Circuit Current Rating @ 13.8 *kV*	Breaker Type	Interrupting Medium
45	3.0	40 kA	Draw Out	SF_6 or vacuum
143	6.0	63 kA	Station Cubicle	SF_6
*478	20.0 or greater	100 kA OR GREATER	In-line isolated-phase bus	SF_6 or air blast

* 478 *MVA* @ 20 kA

employ either SF_6 or compressed air insulating and arc extinguishing systems and can incorporate breaker isolating switches in the breaker compartment. This type of breaker requires less space than a station type cubicle breaker but has higher initial cost. It should receive consideration where powerhouse space is at a premium. Technical operating parameters and performance are covered in IEEE C37.013.

(2) The essential features of draw-out metal-clad switchgear and station type cubicle switchgear are covered in IEEE C37.20.2. Essential features of in-line isolated-phase bus-type circuit breakers are covered in IEEE C37.013 and C37.23. Specific current and interrupting ratings available at other voltages are summarized in Tables 6-2 and 6-3.

Table 6-2
Indoor Metal-Clad Switchgear, Removable Breaker Nominal Ratings

Phase protection is by insulated buses

Voltage (*kV*)	Voltage Rating Factor K	Current (kA)	Short-Circuit Rating (kA)	Interrupting Rating (kA)	Closing Mechanism
4.76	1.36	1.2	8.8	12	Stored
4.76	1.24	1.2, 2	29	36	Energy
4.76	1.19	1.2,2,3	41	49	"
8.25	1.25	1.2, 2	33	41	"
15.0	1.3	1.2, 2	18	23	"
15.0	1.3	1.2, 2	28	36	"
15.0	1.3	1.2,2,3	37	48	"
38.0	1.65	1.2,2,3	21	35	"
38.0	1.00	1.2, 3	40	40	"

Note: The voltage range factor, K, is the ratio of maximum voltage to the lower limit of the range of operating voltage in which the required symmetrical and asymmetrical current interrupting capabilities vary in inverse proportion to the operating voltage. See ANSI C37.06.

Table 6-3
Indoor Metal-Enclosed Switchgear, Fixed Breaker Preferred Ratings For Generator Circuit Breakers 4/

Phase protection is by steel barriers

Voltage (*kV*)	Voltage Rating Factor K	Current (kA)	Short-Circuit Rating (kA)	Interrupting Rating (kA)	Closing Mechanism
15.8	1	1/	2/	3/	Stored
27.5	1	1/	2/	3/	Energy

1/ Typical values, in kA: 6.3, 8.0, 10.0, 12.0, 16.0, 20.0, 25.0, 30.0 and 40.0.

2/ Typical values in kA: 63, 80, 100, 120, 160, 200, 250, 275.

3/ Symmetrical interrupting capability for polyphase faults shall not exceed the short-circuit rating. Single-phase-to-ground fault interrupting capability shall not exceed 50A.

4/ IEEE C37.013.

Chapter 7
Station Service System

7-1. Power Supply

a. General. A complete station service supply and distribution system should be provided to furnish power for station, dam auxiliaries, lighting, and other adjacent features of the project. The loss of a station service source, either through switching operations or due to protective relay action, should not leave the plant without service power. The station service system should have a minimum of two full-capacity, redundant power sources.

b. Plant "black start" capability.

(1) General. "Black start" capability is desirable at hydro plants since the plants can assist in re-establishing generation for the power system in an emergency. "Black start" capability is defined as the ability of the plant, without an external source of power, to maintain itself internally, start generating units, and bring them up to speed-no-load conditions, close the generator breakers, energize transformers and transmission lines, perform line charging as required, and maintain units while the remainder of the grid is re-established. The plant must then resynchronize to the grid.

(2) Power system problems.

(a) There are a number of circumstances that can lead to collapse of all or parts of a bulk power distribution system. Regardless of the circumstances, the triggering event generally leads to regional and subregional mismatch of loads and generation and "islanding" (i.e., plants providing generation to isolated pockets of load). Separation of generation resources from remote loads and "islanding" can cause voltage or frequency excursions that may result in the loss of other generation resources, particularly steam generation, which is more sensitive to frequency excursions than hydroelectric turbine generators. Steam generation is also harder to return to service than hydro generation, so the burden of beginning system restoration is more likely to fall on hydro resources.

(b) When a transmission line is removed from service by protective relay action, the power it was carrying will either seek another transmission line route to its load, or be interrupted. If its power is shifted to other transmission lines, those lines can become overloaded and also be removed from service by protective relays. System failures are more likely to happen during heavy load periods, when failures cascade because of stress on the system. If the hydro units are running at or near full load when the plant is separated from the system, they will experience load rejections.

(c) Units subjected to a load rejection are designed to go to speed-no-load until their operating mode is changed by control action. Sometimes, however, they shut down completely, and if station service is being supplied by a unit that shuts down, that source will be lost. Units can't be started, or kept on line, without governor oil pressure, and governor oil pressure can't be maintained without a source of station service power for the governor oil pumps.

(d) Assumptions made concerning plant conditions when the transmission grid collapses, thus initiating the need for a "black start," will define the equipment requirements and operating parameters which the station service design must meet. At least one emergency power source from an automatic start-engine-driven generator should be provided for operating governor oil pumps and re-establishing generation after losing normal station service power.

c. For large power plants.

(1) Two station service transformers with buses and switching arranged so that they can be supplied from either the main generators or the transmission system should be provided, with each transformer capable of supplying the total station load. A unit that will be operated in a base load mode should be selected to supply a station service transformer, if possible. Station service source selection switching that will allow supply from either a main unit or the power system should be provided. The switching should be done by interlocked breakers to prevent inadvertent parallel operation of alternate sources. If a main unit is switched on as a source, then the supply should not depend on that unit being connected to the power system. If the power system is switched on as the source, then the supply should not depend on any units being connected to the power system.

(2) To meet Federal Energy Regulatory Commission (FERC) requirements, all reservoir projects should be equipped with an engine-driven generator for emergency standby service with sufficient capacity to operate the spillway gate motors and essential auxiliaries in the dam. The unit is usually installed in or near the dam rather than in the powerhouse. It may also be used to provide emergency service to the powerhouse, although the use of long

supply cables from the dam to the powerhouse could be a disadvantage.

(3) For a large power plant, a second automatic start emergency power source may be required in the powerhouse. Besides diesel engine-generators, small combustion turbines are an option, although they are more complex and expensive than diesel engine-generator sets.

(4) Any emergency source should have automatic start control. The source should be started whenever station service power is lost. The emergency source control should also provide for manual start from the plant control point. It is also important to provide local control at the emergency source for non-emergency starts to test and exercise the emergency source. A load shedding scheme may be required for any emergency source, if the source capacity is limited.

d. For small, one-unit power plants. One station service transformer supplied from the transmission system should be provided for a normal station service bus, and an emergency station service bus should be supplied from an engine-driven generator. The emergency source should have sufficient capacity to operate the spillway gate motors and minimum essential auxiliaries in the dam and powerhouse such as unwatering pumps, governor oil pumps, and any essential preferred AC loads.

e. Station service distribution system.

(1) In many plants, feeders to the load centers can be designed for 480-V operation. In a large plant, where large loads or long feeder lengths are involved, use of 13.8-*kV* or 4.16-*kV* distribution circuits will be satisfactory when economically justified. Duplicate feeders (one feeder from each station service supply bus) should be provided to important load centers. Appropriate controls and interlocking should be incorporated in the design to ensure that critical load sources are not supplied from the same bus. Feeder interlock arrangements, and source transfer, should be made at the feeder source and not at the distribution centers.

(2) The distribution system control should be thoroughly evaluated to ensure that all foreseeable contingencies are covered. The load centers should be located at accessible points for convenience of plant operation and accessibility for servicing equipment. Allowance should be made for the possibility of additional future loads.

(3) All of the auxiliary equipment for a main unit is usually fed from a motor control center reserved for that unit. Feeders should be sized based on maximum expected load, with proper allowance made for voltage drop, motor starting inrush, and to withstand short-circuit currents. Feeders that terminate in exposed locations subject to lightning should be equipped with surge arresters outside of the building.

(4) Three-phase, 480-V station service systems using an ungrounded-delta phase arrangement have the lowest first cost. Such systems will tolerate, and allow detection of, single accidental grounds without interrupting service to loads. Three-phase, grounded-wye arrangements find widespread use in the industrial sector and with some regulatory authorities because of perceived benefits of safety, reliability, and lower maintenance costs over a 480-V delta system. Industrial plants also have a higher percentage of lighting loads in the total plant load. Installation costs for providing service to large concentrations of high-intensity lighting systems are lower with 480/277-V wye systems. Delta systems are still preferred in hydro stations because of the cleaner environment, good service record, and skilled electricians available to maintain the system.

f. Station service switchgear.

(1) Metal-clad switchgear with SF_6 or vacuum circuit breakers should be supplied for station service system voltage above 4.16 *kV*. Metal-enclosed switchgear with 600-V drawout air circuit breakers should be used on 480-V station service systems. The switchgear should be located near the station service transformers.

(2) The station service switchgear should have a sectionalized bus, with one section for each normal station service source. Switching to connect emergency source power to one of the buses, or selectively, to either bus should be provided. If the emergency source is only connected to one bus, then the reliability of the station service source is compromised since the bus supplied from the emergency source could be out of service when an emergency occurred. It is preferable that the emergency source be capable of supplying either bus, with the breakers interlocked to prevent parallel operation of the buses from the emergency source.

(3) Each supply and bus tie breaker should be electrically operated for remote operation from the control room in attended stations. As a minimum, bus voltage indication for each bus section should be provided at the remote point where remote plant operation is provided. Transfer between the two normal sources should be automatic. Transfer to the emergency power sources should

also be automatic when both normal power sources fail. Feeder switching is performed manually except for specific applications.

(4) In large station service systems with a double bus arrangement, source/bus tie breakers should be located at each end of the switchgear compartment. The source/bus tie breakers should not be located in adjacent compartments because a catastrophic failure of one breaker could destroy or damage adjacent breakers leading to complete loss of station service to the plant. In large plants where there is sufficient space, it is even safer to provide a separate, parallel cubicle lineup for each station service bus for more complete physical isolation. Even with this arrangement, feeder and tie breakers should not be located in adjacent compartments.

(5) For 480-V station service systems, a delta-connected, ungrounded system is recommended for the following reasons:

(a) Nature of the loads. The load in a hydroelectric power plant is made up predominantly of motor loads. In a commercial or light industrial facility, where the load is predominantly lighting, the installation of a 480/277 V, wye-connected system is more economical due to the use of higher voltages and smaller conductor sizes. These economies are not realized when the load is predominantly motor loads. For high bay lighting systems, certain installation economies may be realized through the use of 480/277-V wye-connected subsystems, as described in Chapter 12.

(b) Physical circuit layout. Wye-connected systems allow the ability to quickly identify and locate a faulted circuit in a widely dispersed area. Although hydroelectric power plants are widely dispersed, the 480-V system is concentrated in specific geographic locales within the plant, allowing rapid location of a faulted circuit, aided by the ground detection system described in paragraph 7-2.

7-2. Relays

An overlapping protected zone should be provided around circuit breakers. The protective system should operate to remove the minimum possible amount of equipment from service. Overcurrent relays on the supply and bus tie breakers should be set so feeder breakers will trip on a feeder fault without tripping the source breakers. Ground overcurrent relays should be provided for wye-connected station service systems. Ground detection by a voltage relay connected in the broken delta corner of three potential transformers should be provided for ungrounded or delta-connected systems (ANSI C37.96). Bus differential relays should be provided for station service systems of 4.16 *kV* and higher voltage. The adjustable tripping device built into the feeder breaker is usually adequate for feeder protection on station service systems using 480-V low-voltage switchgear.

7-3. Control and Metering Equipment

Indicating instruments and control should be provided on the station service switchgear for local control. A voltmeter, an ammeter, a wattmeter, and a watthour meter are usually sufficient. A station service annunciator should be provided on the switchgear for a large station service system. Contact-making devices should be provided with the watthour meters for remote indication of station service energy use. Additional auxiliary cabinets may be required for mounting breaker control, position indication, protective relays, and indicating instruments. For large plants, physical separation of control and relay cubicles should be considered so control and relaying equipment will not be damaged or rendered inoperable by the catastrophic failure of a breaker housed in the same or adjacent cubicle.

7-4. Load/Distribution Centers

Protective and control devices for station auxiliary equipment should be grouped and mounted in distribution centers or, preferably, motor control centers. The motor starters, circuit beakers, control switches, transfer switches, etc., should all be located in motor control centers.

7-5. Estimated Station Service Load

a. General.

(1) The maximum demand that is expected on the station service system is the basis for developing station service transformer ratings. The expected demand may be determined from a total of the feeder loads with an appropriate diversity factor, or by listing all connected loads and corresponding demand loads in *kVA*. A diversity factor smaller than 0.75 should not be used. During high activity periods or plant emergencies, higher than normal station service loads can be expected and if a small diversity factor has been used, the system may not have adequate capacity to handle its loads.

(2) Demand factors used for developing station service equipment capacities can vary widely due to the type of plant (high head stand-alone power plant versus

low head power plant integrated with a dam structure and navigation lock). Development of demand factors for unit auxiliaries should account for the type of auxiliaries in the plant based on trends observed at similar plants. For instance, the governor oil pump demand for a Kaplan turbine will be greater than that for the governor oil pump demand for a Francis turbine of the same output rating because of the additional hydraulic capacity needed to operate the Kaplan turbine blades. If the plant is base loaded, governor oil pumps will not cycle as often as governor oil pumps in a similar plant used for automatic generation control or peaking service.

(3) Station service systems should be designed to anticipate load growth. Anticipated growth will depend on a number of factors including size of the plant, location, and whether the plant will become an administrative center. A one- or two-unit isolated plant not suitable for addition of more units would not be expected to experience a dramatic increase in demand for station service power. For such a plant, a contingency for load growth of 20 percent would be adequate. Conversely, some large multi-purpose plants have experienced 100-percent increases in the connected *kVA* loads on the station service system over original design requirements.

(4) Capacity deficits in existing station service systems have not been caused by the designer's inability to predict unit auxiliary requirements, but by unforeseeable demands to provide service for off-site facilities added to multipurpose projects. Examples of this have been the development of extensive maintenance and warehouse facilities outside the power plant, or electrical requirements resulting from environmental protection issues such as fish bypass equipment. The station service design should have provisions for unanticipated load growth for multipurpose projects with navigation locks and fish ladders. For such projects, a minimum growth factor contingency adder of 50 percent could be justified.

b. Auxiliary demand. Demand varies greatly with different auxiliaries, and the selection of demand factors requires recognition of the way various power plant equipments will be operated. One method illustrated in Table 7-1 assumes 1 *hp* as the equivalent of 1 *kVA* and on lights and heaters uses the *kW* rating as the *kVA* equivalent. The accuracy of the method is within the accuracy of the assumptions of demand and diversity. The values of demand and diversity factors correlate with trends observed in recent years on station service loads.

Table 7-1
Estimated Station Service Load and Recommended Transformer Capacity

Function		Connected Load kVA	Demand kVA
Unit Auxiliaries for 8 Units			
Governor Oil Pump			
Pump #1 Bus #1	8 @ 100 *hp*	800.00	400.00
Pump #2 Bus #2	8 @ 100 *hp*	800.00	
Pump #3 Bus #1	4 @ 25 *hp*	100.00	50.00
Pump #4 Bus #2	4 @ 25 *hp*	100.00	
Turbine Bearing Oil Pump	8 @ 1 *hp*	8.00	8.00
Head Cover Pump			
Pump #1 Bus #1	8 @ 2 *hp*	16.00	16.00
Pump #2 Bus #2	8 @ 2 *hp*	16.00	
High Bay Lights			
Bus #1	7 @ 13 *kW*	91.00	91.00
Bus #2	7 @ 13 *kW*	91.00	
Generator Housing Heater	8 @ 18 *kW*	144.00*	
Transformer Cooling Water Pumps			
Bus #1	2 @ 50 *hp*	100.00	100.00
Bus #2	2 @ 50 *hp*	100.00	
Transformer Oil Pump			
Bus #1	12 @ 2 *hp*	24.00	24.00
Bus #2	12 @ 2 *hp*	24.00	
ACB Air Compressor			
Bus #1	1 @ 5 *hp*	5.00	5.00
Bus #2	1 @ 10 *hp*	10.00	10.00

(Continued)

Table 7-1 (Concluded)

Function		Connected Load *kVA*	Demand *kVA*
High Pressure Thrust			
Bearing Oil Pump	8 @ 10 *hp*	80.00	
Governor Air Compressor	2 @ 15 *hp*	30.00	
General Auxiliaries			
Supply to Dam		696	205
Fire Pump		25	25
HVAC-Heat Pump		380	36
Transit Oil Processor		20	20
Transit Oil Pump		10	10
Battery Charger No. 1		10	10
Battery Charger No. 2		10	0**
Elevator		25	25
Power Outlets		--	25
Draft Tube Crane		50	0
Duplex Sump Pump		15	7.5
Powerhouse Crane No. 1		100	0
Air Compressor No. 1		20	20
Air Compressor No. 2		20	0**
Filter Paper Oven		2	2
Lubricating Oil Purifier		14	14
Lubricating Oil Pump		5	0
Water Heater - 20 gal.		2	2
Water Heater - 100 gal.		5	2
Switchyard			
Cable Tunnel Ventilating Fan		5	5
Power Outlets		-	5
Lighting		37.5	30
Air Compressors		6	2
Machine Shop			
Largest Machine		____	15
Total less heating		3852.5	1164.50
Total demand with diversity factor of 75 percent			873.4 kVA
Estimated total heating load			1055.0 kVA
Estimated total demand load with heating			1928.4 kVA
Recommended size of each station service transformer			1500.0 kVA

* Not on when generator running.
** Standby

Chapter 8
Control System

8-1. General

a. Scope. The control system as discussed in this chapter deals with equipment for the control and protection of apparatus used for power generation, conversion, and transmission. It does not include low-voltage panelboards and industrial control equipment as used with plant auxiliaries. IEEE 1010 and EPRI EL-5036, Volume 10, provide guidelines for planning and designing control systems for hydroelectric power plants.

b. Control system components. The control system consists primarily of a computer-based control system, hard-wired logic or programmable logic, indicating and recording instruments, control switches, protective relays, and similar equipment. The greatest part of this equipment should be grouped at one location to facilitate supervision and operation of the main generating units, transmission lines, and station auxiliaries. The grouping of these controls at one location within the confines of the power plant is termed "centralized control."

c. Start-stop sequence. Each generator unit control system should be provided with a turbine/generator start-stop sequencing logic using a master relay located at the generator (or unit) switchboard. The starting sequence begins with pre-start checks of the unit, followed by starting unit auxiliaries, and ends with the unit operating under the speed-no-load condition. Manual or automatic synchronizing and closure of the unit breaker can be performed at the local control location. The stopping sequence should provide for four types of unit shutdown: protective relaying, operator's emergency stop switch, mechanical problems, and normal shutdown.

d. Generator switchboards. Generator switchboards in larger power plants are located near the controlled generator. The switchboards provide local control of the unit. In smaller power plants, where metal-clad switchgear is used for switching the generator, unit control equipment is located on auxiliary panels of the switchgear line-up. Like the switchboards, the auxiliary panel equipment provides local control of the unit.

e. Auxiliary equipment control. Large power plants using high-voltage busing and switching or having an adjacent switchyard as part of the development should have control for this equipment located in the grouping suggested in paragraph 8-1(*b*). Even though the controlled equipment is remote from the plant, the equipment is not "offsite." Offsite control denotes control from a location not resident to the plant, i.e., another plant or a control complex at another location.

f. Control room location. In plants with a few units, the control room location with its centralized controls should provide ready access to the governor control cabinets. In plants with ultimately four or more units, the control room should be located near the center of the ultimate plant or at a location allowing ready access to the units and adjacent switchyard. The relative number and lengths of control circuits to the units and to the switchyard is a factor to consider, but is secondary to consideration of operating convenience. The control room should be an elevation above maximum high water, if there is any danger that the plant may be flooded. A decision on the location of the control room should be reached at an early stage of plant design, since many other features of the plant are affected by the control room location. Control location definitions and control modes are further described in IEEE 1010.

g. Smaller plants. In smaller power plants, where indoor generator-voltage busing and switching are used, hinged instrument panels on the switchgear cubicles should be used as mounting space for main control equipment. This results in the main group of control equipment being located at the main switchgear location.

8-2. Control Equipment

a. General. Centralized automatic and manual control equipment should be located in the control room of large power plants. The control console, in conjunction with supervisory control and data acquisition (SCADA) equipment and the status switchboard, enables the control room operator to control the powerhouse operation. Equipment racks housing automatic synchronizing and centralized auxiliary equipment should be located in or adjacent to the control room to facilitate connections with control room equipment. If the plant is controlled from offsite, the plant's SCADA equipment should be located in or adjacent to the control room.

b. Space allocation. Space allotted for control equipment, whether in a separate control room or in the main switchgear cubicle area, must be large enough to accommodate the panels required for the ultimate number of generating units and transmission lines. The space requirement, as well as the size and location of openings required in the floor, should be provided to the architectural and structural designers to ensure proper consideration in door, room, and floor slab designs.

c. Cabinet construction. Generator switchboard panels and doors should be 1/8-in. thick or No. 11 U.S.S. gauge smooth select steel with angle or channel edges bent to approximately a 1/4-in. radius. Panels should be mounted on sills ready for powerhouse installation in groups as large as can be shipped and moved into the installation area. All equipment on the switchboards should be mounted and wired at the factory, and the boards should be shipped to the powerhouse with all equipment in place.

d. Equipment arrangement. The arrangement of equipment on the control switchgear, switchboard, or control console should be carefully planned to achieve simplicity of design and to replicate unit control placements familiar to the intended operating staff. Simplicity of design is a definite aid to operation and tends to reduce operating errors; therefore, the relative position of devices should be logical and uniform. Switchboard and control console design should be patterned after an appropriate example to attain a degree of standardization in the arrangement of indicating instruments and basic control switches. Control switches should be equipped with distinctive handles as shown in Table 8-1. Each item of equipment should be located by consideration of its functions, its relation to other items of equipment, and by its use by the operator.

8-3. Turbine Governor

The digital governor electrical control cabinet usually is located adjacent to the generator switchboard separate from the actuator cabinet. The control cabinet contains governor electronic or digital “proportional-integral-derivative” (P-I-D) control components. The actuator cabinet housing the power hydraulics of the governor system is located to minimize the pressure line runs between the turbine servomotors, the actuator, and the governor pressure tank. For smaller capacity governors and smaller plants, governor electronic and hydraulic controls are all located in the governor actuator cabinet. For mechanical considerations of turbine governors, see EM 1110-2-4205.

8-4. Large Power Plant Control

a. General. Centralized control system equipment is located in the control room and is interconnected to the generator switchboards located near the units. Required control and monitoring of all functions of the hydroelectric power project are provided to the operators. The control console with conventional control devices and monitoring equipment in conjunction with a computer-based data acquisition and control system (DACS), provides control and indication access to individual items of equipment to facilitate operation, supervision, and control. Hard-wired pushbutton switches provide for direct operator manual control of unit start-stop, breaker close (initiating automatic synchronizing), breaker trip, voltage, loading, and gate limit raise-lower. Analog or digital panel meters and indicating lights continuously indicate the status of all main units, breakers, transformers, and lines. The DACS system display monitors and keyboards are available to operator control. The unit controls and instruments supplement or duplicate those on the generator switchboard, and provide the control room operator with the ability to transfer control of any selected unit or group of units to the generator switchboard in case of system trouble. The control console may also provide spillway gate control, fishway control, project communications, and other project equipment control functions when required.

b. Equipment location. Arrangement of control and instrument switches and mimic bus should simulate the relative order of interconnections or physical order of the plant arrangement assisting the operator in forming a mental picture of connections. The top of the control console panel should be inclined to provide easier access to the control switches and to improve console visibility. Layouts of console visual display terminals (VDTs) should follow applicable guidelines contained in Chapter 12, “Lighting and Receptacle Systems,” to ensure good visual acuity of the displays. Panels of the control console should be arranged for ultimate development, so that the addition of a control panel for another generator or another line will not disturb existing equipment.

c. Status switchboard. The status switchboard contains graphic and visual indication, generator load recorders, station total megawatts and megavars recorders, and other required project data displays. The status switchboard should be located for easy observation from the control console. The status switchboard should be a standard modular vertical rack enclosure joined together to form a freestanding, enclosed structure.

d. Equipment racks. Equipment racks should be provided for mounting line relays, automatic synchronizing equipment, the common and outside annunciator chassis, auxiliary relays, communication equipment, and transfer trip equipment. The equipment racks should be standard, modular, vertical rack enclosures.

Table 8-1
Typical Plant Control and Instrument Switch Data

Switch Function	Contact Type*	No. Pos	Handle Type**	Namplate Marking***	Escutcheon or Dial Marking Pos-1	Pos-2	Pos-3	Pos-4	Ind Lights
Exciter AC Voltage Control	A	3	BPG	AC VOLT ADJUST	LOWER	-	RAISE		
Excitation Breaker Control	A	3	BPG	EXC BKR	TRIP	-	CLOSE		G,R
Exciter DC Voltage Adjust	A	3	BPG	DC VOLT ADJUST	LOWER	-	RAISE		R,A,A,G
Generator Breaker Control	A	3	BPG	GEN PCB	TRIP	-	CLOSE		G,R
Generator Start/Stop Control	A	3	BPG	UNIT START-STOP	STOP	-	START		G,R
Emergency Shutdown (Main Unit)	A	-	RPG	EMERG SHUTDOWN	PULL	AND	TURN		--
Governor Gate Limit Control	A	3	BO	GATE LIMIT	RAISE	-	LOWER		--
Governor Speed Level Control	A	3	BO	SPEED ADJ	RAISE	-	LOWER		--
Synchronizing (Main Units)	B	2	RBO	SYNCH	OFF	ON			--
Synchronizing (Switchyard)	B	3	RBO	SYNCH	RUN	OFF	INC		--
Transf, Oil Pump Motor Control	A	3	BPG	TRANSF OIL PUMPS	STOP	-	RUN		G,R
Lind M.O. Disc. Switch Control	A	3	BPG	LINE SW	OPEN	-	CLOSE		G,R
Aux Bus M.O. Sectionalizing Switch Control	A	3	BPG	AUX BUS SW	OPEN	-	CLOSE		G,R
M.O. Disc. Control InterLock	A	3	BPG	INTERLOCK	OPEN	-	CLOSE		--
Ammeter Transfer Switch	B	4	BK	GEN AM	A	B	C	OFF	
Voltmeter Transfer Switch	B	4	BK	GEN VM	OFF	A-B	B-C	C-A	
Volt Regulator Transfer Switch	B	3	BPG	VOLT REG	OFF	MAN	REG		W,R
Bus Tie PCB Control	A	3	BPG	BUS TIE PCB	TRIP	-	CLOSE		G,R

*TYPE A - Momentary Spring Return to Neutral
TYPE B - Maintained
** BPG - Black Pistol Grip
RPG - Red Pistol Grip
BO - Black Oval
RBO - Removable Black Oval
BK - Black Knurled
***To suit each application

e. SCADA equipment. The SCADA and communication equipment should be located in the general control area.

8-5. Small Power Plant Control

a. General. Small power plants using medium-voltage metal-clad switchgear for generator control impose different limitations on equipment arrangements than arrangement limitations of generator switchboards for local unit control. This is due to the variety of equipment available with switchgear and, consequently, the different possibilities for locations for major control equipment. As noted in paragraph 8-1*g*, hinged instrument panels on the main switchgear can be used for control equipment. Where space and switchgear construction allow, it is desirable to have hinged instrument panels on the side of the stationary structure opposite the doors for removing the breakers. These panels, however, provide space for only part of the necessary control equipment, and one or more auxiliary switchgear compartments will be required to accommodate the remaining equipment.

b. Equipment location. Annunciator window panels, indicating instruments, control switches, and similar equipment should be mounted on the switchgear hinged panels. The hinged panel for each breaker section should be assigned to the generating unit, transmission line, or station service transformer that the breaker serves and only the indicating instruments, control switches, etc., associated with the controlled equipment mounted on the panel. A hinged synchronizing panel should be attached to the end switchgear cubicle.

c. Additional equipment location. Protective relays, temperature indicators, load control equipment, and other equipment needed at the control location and not provided for on the switchgear panels should be mounted on the auxiliary switchgear compartments.

d. SCADA equipment. Small power plants are frequently unattended and remotely controlled from an off-site location using SCADA equipment. The SCADA and communication equipment should be located in the general control area.

8-6. Protective Relays

a. General. The following discussion on protective relays includes those devices which detect electrical faults or abnormal operating conditions and trip circuit breakers to isolate equipment in trouble or notify the operator through alarm devices that corrective action is required. The application of relays must be coordinated with the partitioning of the electrical system by circuit breakers, so the least amount of equipment is removed from operation following a fault, preserving the integrity of the balance of the plant's electrical system.

(1) Generally, the power transmitting agency protection engineer will coordinate with the Corps of Engineers protection engineer to recommend the functional requirements of the overlapping zones of protection for the main transformers and high voltage bus and lines. The Corps of Engineers protection engineer will determine the protection required for the station service generators and transformers, main unit generators, main transformers, and powerhouse bus.

(2) Electromechanical protective relays, individual solid state protective relays, multi-function protective relays, or some combination of these may be approved as appropriate for the requirements. Traditional electromechanical protective relays offer long life but may malfunction when required to operate, while many less popular designs are no longer manufactured. Individual solid state protective relays and/or multi-function protective relays offer a single solution for many applications plus continuous self diagnostics to alarm when unable to function as required. Multi-function protective relays may be cost-competitive for generator and line protection when many individual relays would be required. When multi-function relays are selected, limited additional backup relays should be considered based upon safety, the cost of equipment lost or damaged, repairs, and the energy lost during the outage or repairs if appropriate.

(3) When the protection engineer determines that redundancy is required, a backup protective relay with a different design and algorithm should be provided for reliability and security. Fully redundant protection is rarely justified even with multi-function relay applications. Generators, main transformers, and the high voltage bus are normally protected with independent differential relays.

(4) When the protective relays have been approved, the protection engineer will provide or approve the settings required for the application.

b. Main generators.

(1) The general principles of relaying practices for the generator and its excitation system are discussed in IEEE standards C37.101, C37.102, and C37.106.

Unless otherwise stated, recommendations contained in the above guides apply to either attended or unattended stations.

(2) Differential relays of the high speed, percentage differential type are usually provided to protect the stator windings of generators rated above 1500 *kVA*.

(3) A high-impedance ground using a resistance-loaded distribution transformer scheme is generally used, thereby limiting generator primary ground fault current to less than 25 A. A generator ground, AC overvoltage relay with a third harmonic filter is connected across the grounding impedance to sense zero-sequence voltage. If the generator is sharing a GSU transformer with another unit, a timed sequential ground relay operation to isolate and locate generator and delta bus grounds should be provided.

(4) Out-of-step relays are usually provided to protect generators connected to a 500-*kV* power system, because the complexity of a modern EHV power system sometimes leads to severe system frequency swings, which cause generators to go out of step. The generator out-of-step relays should incorporate an offset mho and angle impedance relay system which can detect an out-of-step condition when the swing locus passes through the generator or its transformer.

(5) Frequency relays, and under- and over-frequency protection, are not required for hydraulic-turbine-driven generators.

(6) Temperature relays are provided for thrust and guide bearings as backup for resistance temperature detectors and indicating thermometers with alarms. The relays are set to operate at about 105° C and are connected to shut down the unit. Shutdown at 105° C will not save the babbitt on the bearing but will prevent further damage to the machine.

c. Generator breakers.

(1) Most breaker failure relaying schemes operate on high phase or ground currents. When a trip signal is applied to the breaker, the breaker should open and current flow should cease within the breaker interrupting time. The breaker failure relay is usually applied to operate lockout relays to trip backup breakers after a time delay based on the assumption the breaker has failed if current flow continues after the breaker trip circuit has been energized. These schemes do not provide adequate protection if breaker failure occurs while current is near zero immediately following synchronizing.

(2) Another scheme uses a breaker auxiliary contact to detect breaker failure with fault detectors for phase current balance, reverse power, and overcurrent relays. Protective relay contact closing or operation of the breaker control switch to the trip position energizes a timing relay. If the breaker auxiliary contact does not close within the breaker interrupting time, the timing relay will close its contacts, enabling the phase current balance, reverse power, and overcurrent relays to perform the required trip functions.

(3) Some breaker control systems monitor the breaker trip coil using a high resistance coil relay connected in series with the trip coil. A time delay relay is required to allow the breaker to open during normal tripping without initiating an alarm.

(4) Provision should be made to trip generator breakers when there is a loss of the breaker trip circuit DC control power or complete loss of DC for the entire plant. A stored energy capacitor trip device can be used to trip the breaker in case of a loss of control power.

d. Transformer protection.

(1) Transformers or transformer banks over 1500 *kVA* should be protected with high-speed percentage-type differential relays. The basic principles involved in transformer protection are discussed in IEEE C37.91.

(2) Separate differential relay protection for generators and transformers should be provided even on unit installations without a generator circuit breaker. The relays applicable for generators can be set for much closer current balance than transformer differential relays.

(3) Auto transformers can be treated as three-winding transformers and protected with suitable high-speed differential relays. The tertiary winding of an auto-transformer usually has a much lower *kVA* rating than the other windings. The current transformer ratios should be based on voltage ratios of the respective windings and all windings considered to have the same (highest) *kVA* rating.

(4) Thermal relays supplement resistance temperature detectors and thermometers with alarm contacts. The relays are set to operate when the transformer temperature reaches a point too high for safe operation, and are

connected to trip breakers unloading the transformers. These relays are important for forced-oil water-cooled transformers which may not have any capacity rating without cooling water.

e. Bus protection.

(1) High-voltage switchyard buses can be protected with bus protection, but the necessity and type of bus protection depends on factors including bus configuration, relay input sources, and importance of the switchyard in the transmission system. Application of bus protection should be coordinated with the PMA or utility operating agency. The basic principles of bus protection operation are discussed in IEEE C37.97.

(2) Large power plants with a complex station service system configuration should be provided with station service switchgear bus differential relay protection.

(3) A ground relay should be provided on the delta-connected buses of the station service switchgear. A voltage relay, connected to the broken-delta potential transformer secondary windings, is usually provided to detect grounds. A loading resistor may be placed across the broken delta to prevent possible ferroresonance. The ground detector usually provides only an alarm indication.

f. Feeder protection. Feeder circuits that operate at main generator voltage and 4160-V station service feeders should be protected with overcurrent relays having instantaneous trip units and a ground relay. The setting of the ground relay should be coordinated with the setting of the generator ground relay to prevent shutdown of a generator due to a grounded feeder.

g. Transmission line protection. Relays for the protection of transmission lines should be selected on the basis of dependability of operation, selectivity required for coordination with existing relays on the interconnected system, speed of operation required to maintain system stability, coordinating characteristics with relays on the other end of the line, and the PMA or utility system operating requirements. The basic principles of relaying practices are discussed in IEEE C37.95.

h. Shutdown relays. The shutdown lockout relays stop the unit by operating shutdown equipment and tripping circuit breakers. The lockout relay operations are usually divided into two groups. A generator electrical lockout relay, 86GX, is initiated by protective relaying or the operator's emergency trip switch. The generator mechanical lockout relay, 86GM, is triggered by mechanical troubles, such as bearing high temperatures or low oil pressure. The unit shutdown sequence is described in IEEE 1010.

8-7. Automatic Generation Control (AGC)

For computer-based control systems, unit load can be controlled in accordance with an error signal developed by digital computers periodically sampling real power flow over the tie line, line frequency, and generator power output. These analog signals are continuously monitored at the load dispatch control center to obtain the plant generation control error. The control error digital quantity is transmitted via telemetry to each plant and allocated to the units by the computer-based plant control system. AGC action by the plant control system converts the raise/lower megawatt signal into a timed relay contact closure to the governor. The governor produces a wicket gate open/close movement to change the generator output power. Other modes of operation include set point control, regulating, base loaded, ramped control, manual control, and others relative to the nature of the project and operating philosophy. Coordination of the engineering planning of the AGC with the marketing agency should begin at an early stage.

Chapter 9
Annunciation Systems

9-1. General

EPRI EL-5036, Volume 10, provides guidelines and considerations in planning and designing annunciation systems for power plants.

9-2. Audio and Visual Signals

Every power plant should be provided with an annunciation system providing both audible and visual signals in the event of trouble or abnormal conditions.

a. Audio signals. Howler horns and intermittent gongs are used for audible signal devices. An intermittent gong is provided in the plant control room. Howler horns are used in the unit area and in areas where the background noise is high (e.g., in the turbine pit) or in areas remote from the unit (e.g., plant switchyard).

b. Visual signals. Visual signals are provided by lighted lettered window panels of the annunciator. In larger plants, the annunciator panel indication is augmented by unit trouble lamps located in a readily visible position close to the unit. The plant sequence of events recorder (SER) is normally located in the control room. Separate annunciators (when provided) for station service systems and switchyards should be located on associated control panels of the station service switchgear or on the switchyard control panels.

9-3. Annunciator

a. General. The annunciator system should be designed for operation on the ungrounded 125-V DC system discussed in Chapter 11. All remote contacts used for trouble annunciation should be electrically independent of contacts used for other purposes so annunciator circuits are separated from other DC circuits. Auxiliary relays should be provided where electrically independent contacts cannot otherwise be obtained. The annunciator equipment should use solid-state logic units, lighted-window or LED type, designed and tested for surge withstanding capability in accordance with ANSI C37.90.1, and manufactured in accordance with ANSI/ISA S18.1.

b. The switchboard annunciator operational sequence should be a manual or automatic reset sequence as listed in Table 9-1.

Automatic reset should be employed when there is either an SER or a SCADA system backup. When the plant is controlled and dispatched through the SCADA system of the wheeling utility, the design reset features of the annunciator should be coordinated to ensure proper operation.

c. The generator switchboard is provided with annunciator alarm points for unit emergency shutdown, generator differential lockout, generator incomplete start, generator or 15-kV bus ground, generator overspeed, generator overcurrent, generator breaker low pressure, unit control power loss, generator CO_2 power off, PT fuse failure or undervoltage, and head cover high water.

Table 9-1
Switchboard Annunciator Operational Sequence

Field Contact	Control Pushbutton or Switch	Alarm Lights	Horn	Auxiliary or Repeater Contacts
Normal	--	Off	Off	Off
Abnormal		Flashing	On	On
Abnormal	Acknowledge or Silence	On	Off	On
Normal	Reset	Off	Off	Off
Normal	Test	On	Off	Off

Certain alarm points have several trouble contacts in parallel by equipment group. Examples include generator excitation system trip or trouble, turbine bearing oil trouble, generator cooling water flow, unit bearing overheat, generator oil level, generator stator high temperature, and governor oil trouble.

d. The generator switchboard may be provided with an additional annunciator for the generator step-up transformer and unit auxiliary equipment alarms, depending on the plant arrangement. Generally, these alarm points are transformer differential, transformer lockout trip, transformer overheat, transformer trouble, 480-V switchgear trip, and trouble.

e. The generator excitation cubicle is provided with an annunciator for excitation equipment alarm points for AC regulator trip, bridge overtemperature, transformer over temperature, regulator power supply, field overvoltage, maximum excitation limit, minimum excitation limit, and volt per Hertz. Generator overvoltage, power system stabilizer, and fan failure alarm points should be included when required.

f. The switchboard annunciator for large power plants should be provided with auxiliary or repeater contacts to drive control room console remote annunciator word-indicating lights.

g. A control console window-indicating light annunciator is common to all units. One unit at a time can be selected by use of the appropriate unit trouble status lighted pushbutton. Visual indication is provided when the unit switchboard annunciator is activated. The console window indicating lights are generally grouped by switchboard annunciator points and provide essential trouble status to the operator. Unit troubles are normally categorized by shutdown, differential, overcurrent, cooling water, bearing oil, unit trouble, breaker air, CO_2 discharge, control power, and head cover high water. The window indicating light annunciator provides backup for a sequential event recorder. Unit switchboard annunciator remote control switches to silence and reset the switchboard annunciator should be provided on the control console.

9-4. Sequence of Events Recorder (SER)

An SER should be provided to complement the plant annunciation system if a SCADA system is not performing the sequence of events function. The SER provides a time-tagged, sequenced, printed record of trouble events. The documented record of a trouble event aids in diagnosing power plant forced outages. It is designed for operation on an ungrounded 125-V DC system. All inputs should be optically isolated and filtered for 125-V DC dry contact change-of-state scanning. The SER minimum resolution should be coordinated with using agencies. A value of 2 msec is typical. When an input signal status change occurs, the SER should automatically initiate and produce a tabulated printed record on the data logger identifying the event and showing the time of status change (to the nearest millisecond). The SER should be provided with a system clock and time synchronization features. Each SER system should be provided with an adequate input point capacity to monitor each alarm trouble contact and provide plant breaker status necessary for the plant operation. The alarm trouble contacts should include IEEE 1010 requirements and project alarm points requirements.

9-5. Trouble Annunciator Points

All of the alarm points listed in Table 9-2 below are not required in every plant, and, conversely, requirements for an unlisted alarm point may arise. IEEE 1010 provides types of alarm signals transmitted to the generator annunciator from the generator, excitation system, generator terminal cabinet, generator breaker, step-up transformer, turbine, and governor, which are listed in Table 9-2.

Table 9-2
Alarm Signals Transmitted to the Generator Annunciator

Generator Switchboard Annunciator Points

Signal	Description
86GX & 86GT	Unit Emergency Shutdown
87GX	Generator Differential Shutdown
48TDC	Generator Incomplete Start
64X	Generator or 15-*kV* Bus Ground
12G	Generator Overspeed
51GAR	Generator Overcurrent
63	Generator Breaker Low Pressure

(Continued)

Table 9-2. (Continued)

Generator Switchboard Annunciator Points

Signal	Description
74CB	Control Power Loss
63X	CO_2 Discharge
27CO_2	CO_2 Power Off
27G	PT Fuse Fail or Undervoltage
71HC	Head Cover High Water
*	Generator Regulator Trip or Trouble
*	Turbine Bearing Oil Trouble
*	Generator Cooling Water Flow
*	Unit Bearing Oil Trouble
*	Generator Oil Level
*	Generator Stator High Temperature
*	Governor Oil Trouble

* See IEEE 1010

Step-Up Transformer Annunciation Points

Signal	Description
87TAR	Transformer Differential
86L	Transformer Lockout Trip (Includes Transformer Ground)
74TL	Transformer Control Power Loss
*	Transformer Overheat
*	Transformer Trouble
20TDX	Transformer Deluge

* See IEEE 1010

Line Annunciation Points

Signal	Description
94L1	Line Lockout
74	Line Relay or MW Power Off
74	Microwave Trouble

Station Service Transformer Annunciation Points

Signal	Description
86T	Transformer Lockout
63G,49,26Q,71Q	Transformer Trouble
94	Transformer Breaker Tripped
63X	CO_2 Discharge

Station Annunciation Points

Signal	Description
86BD	Station Service Switchgear Bus Differential
BA	Station Service Switchgear DC Trouble

Station Annunciation Points

Signal	Description
63	Station Service Switchgear Breaker Low Pressure
94	Station Service Feeder Breaker Tripped

(Continued)

Table 9-2. (Concluded)

BA	480-V AC Feeder Breaker Tripped
64,BA	Bus Tie Breaker Tripped or Trouble
74	Battery Charger Failure
BA	125-V DC Feeder Breaker Tripped
64,74,27	125-V DC System Tripped
64,74,27	48-V DC System Trouble
BA	48-V DC Feeder Breaker Trip
74,83	Inverter Trouble
71	Unwatering Pump Trouble
71	Drainage Pump Trouble
71	Septic Tank High Level
71	Effluent High Level
63	Station Air Low Pressure
63	Oil or Paint Storage Room CO_2 Discharge
27	Fire Pump Power Off
42	Fire Pump On
74,71	Engine Generator Trouble
94	Engine Generator Trip
74	Plant Intrusion Detector

Switchyard Annunciation Points

Signal	Description
63	Power Circuit Breaker Loss of Tripping and Closing Energy
63	Power Circuit Breaker Energy Storage System Energy
27	Breaker Close Bus Failure
27	Breaker Trip Bus Failure
86	Breaker Failure Lockout Relay
27	Relay Potential Failure
21	Line Distance Relay Trip
50/51L	Line Overcurrent Relay Trip
64L	Line Ground Relay Trip
94L	Microwave Transfer Trip
74	MWTT Trouble
86BD	Bus Failure Lockout Relay
74	Line Communication Trip
42	Transformer Cooling Fan Failure
49	Transformer Overheat
71G	Transformer Gas Accumulator
71Q	Transformer Oil Level
63Q	Transformer Sudden Pressure Relay
51G	Transformer Ground Detector
63G	Transformer Inert Air Tank Pressure
86T	Transformer Lockout Relay
87T	Transformer Phase Differential
50/51T	Transformer Phase Overcurrent

Switchyard Annunciation Points

Signal	Description
50G	Transformer Neutral Overcurrent
28	Transformer Fire
74	Battery Charger Trouble
27,64,74	Battery Trouble
74,83	Inverter Trouble
42	Engine Generator Running
71,74	Engine Generator Trouble
74	Yard Intrusion Detector

Chapter 10
Communication System

10-1. General

a. Types of systems available. Reliable communication systems are vital to the operation of every power plant. Voice communication is a necessity at all plants and code-call signaling is generally required for accessing personnel at large power plants. Additional dedicated communication systems are required for telemetering, SCADA, and for certain types of protective relaying. Communications media available for power plant application include: metallic cable pairs; leased telephone lines; power line carrier (PLC); radio frequency communications, including two-way land mobile (TWLM) radio and terrestrial microwave (*MW*); fiber optics; and satellite communications.

b. Regulatory requirements. The Federal Information Resource Management Regulation (FIRMR), as administered by the General Services Administration (GSA), requires GSA approval for all communication systems (other than military) used by agencies of the Federal Government. The GSA contract with common carriers guarantees carriers access to Government long-distance communication business. The service to provide long-distance communications is known as FTS 2000. The GSA requires its use by Government agencies, unless the agencies are able to prove, on a case-by-case basis, that the FTS 2000 service will not meet its needs. For information on the FIRMR, and approval documentation needed, contact the Corps of Engineers Information Management Office.

10-2. Voice Communication System

a. Telephone service. Normally, general internal and external telephone communications are provided through public switched telephone network services installed and operated by the serving telephone company. The equipment (including telephones) is leased from the telephone company. The communication circuits provided by a commercial telephone operating company include connection to local exchange, long distance, WATS, and FTS 2000 telephone service. Telephone pay stations in visitor areas should be provided for public convenience.

b. Plant equipment. The distributing frame and switching equipment for any commercial systems should be installed in a location near the control room where it can be included in the air conditioning zone for the control room. A preferred AC circuit should be provided for the commercial equipment.

c. Telephone locations. To ensure adequate telephone access, sufficient telephone outlets should be provided in the office area, the control room, the generator floor at each unit, the switchgear area, the station service area, and the plant's repair shops. A telephone outlet should be provided in each elevator cab. Circuits to telephone outlets are provided by metallic cable pairs. Telephone wiring inside the plant, from the telephone company switching equipment location to the location of the various instruments, is provided by the Government and included in the powerhouse design. Embedded conduits dedicated to telephone use are provided for the cables.

10-3. Dedicated Communications System

a. General. Dedicated communications systems are provided in the plant for code call systems, SCADA systems, protective relay systems, and for voice communications to the dispatching centers and substations of the power wheeling entity (either Federal Power Marketing Agency (PMA) or non-Federal utility). Communications media for performing these functions can be either leased commercial circuits, power line carrier (PLC), radio frequency communications, fiber-optic cable, satellite communications, or a combination of these media.

b. Code call system. Generally, code-call facilities are provided at all plants permitting paging of key personnel. A separate, Government-owned code-call system should be provided when leased telephones are used, so maintenance of the code call will not depend on outside personnel. An automatic repeating type code-sending station should be located on the control room operator's desk or console.

c. Utility telephone systems.

(1) Voice communications facilities for power plant control and dispatch use are typically provided through a utility or Federal PMA-owned telephone system. If it is a Federally owned system, the FIRMR requires the use of FTS2000 for inter-local access and transport area service, unless an exception is granted. In some instances, the major use of the communication channel has been the determining factor in whether Government ownership of the system is permitted. If the major use of the service is technical; that is, plant operating and control information, then Government ownership has been approved.

(2) The telephone system should provide access to dispatching voice channels of the utility. Generally, dial automatic telephone switching facilities provide a system-wide network of voice circuits which are automatically switched to permit calling between generating stations, major substations, and control centers. Some plants have used leased private line service for communications circuits which are provided by a commercial telephone company's common carrier for the sole use of the plant. These circuits are provided on the cable and other transmission facilities of the carrier, but should not be connected directly to the network switching systems of the carrier or telephone operating company.

d. Leased circuits.

(1) Leased commercial circuits can be used for voice communication circuits as described in paragraph 10-3*c*. Voice grade communication channels are required and are supplied either through a dial or a dedicated system, with dedicated channels being the preferred alternative. The basic voice-bandwidth private line channel is an AT&T system "Type 3002 unconditioned" channel. Other commercially available private line data channel services are Digital Data Service (DDS) and Basic Data Service (BDS). These latter services offer digital interconnectivity through a wide range of data transmission speeds.

(2) Leased circuits have been used for plant protective relaying circuits with mixed results. Generally, it is better to own the communication facility if it is used for vital high-speed relaying service. Some of the past problems with leased channels have been loss of service because of unannounced maintenance activity by the leasing agency, failure of the system, rerouting of the service because of maintenance or construction activity, and accidental circuit interruption by personnel looking for trouble on other circuits. Typically, a leasing agency's operating and maintenance personnel do not understand the level of reliability necessary for relaying circuits.

(3) Leased circuits have been used for SCADA system control of plants and substations. Here, too, the results have been mixed. For short distances where the leasing agency can provide a direct link between the local and remote station, results have been good. Where the circuit has been routed through a central office, the reliability of service has in a number of cases not been of the level of reliability needed for data acquisition and control. The lack of reliability is apt to be more of a problem if the plant is in a remote location and served by a small telephone company. Use of leased facilities has to be considered on a case-by-case basis, and all of the influencing factors need to be considered, including the service record of the proposed leasing agency.

e. Power line carrier.

(1) A "basic" PLC system consists of three distinct parts:

(a) The terminal assemblies, consisting of the transmitters, receivers, and associated components.

(b) The coupling and tuning equipment, which provides a means of connecting the PLCs terminals to the high-voltage transmission line.

(c) The high-voltage transmission line, which provides the path for transmission of the carrier energy. High-voltage coupling capacitors are used to couple the carrier energy to the transmission line, and simultaneously block 60-Hz power from the carrier equipment.

(2) Most transmitter/receiver equipment is installed in standard 19-in. radio racks inside cabinets located near the plant control room. Carrier frequency energy is conducted out of the plant by coaxial cable to the high-voltage transmission line tuning and coupling equipment. PLC equipment power requirements are supplied from either 48-V or 125-V DC derived from the station battery or a dedicated communications battery source. If a PLC system is to be provided, routing provisions for the wire and cables needed must be included in the plant design.

(3) Power line carrier communication systems have found extensive use for relaying, control, and voice communications in Europe, and in some areas of the United States. Their use is less popular in the United States, apparently because of the availability of radio frequency spectrum, and utility-owned communication systems apart from the power transmission facilities. PLC bandwidth is limited because of its operating frequencies and the transmission medium. Its transmission path is susceptible to noise from arcing faults, interruption by ground faults and other accidents to the line, and weather. If other reliable communication means are available at a reasonable cost, it would probably be advantageous to avoid the use of PLC.

f. TWLM radio.

(1) There is some very limited use of TWLM radio in SCADA systems using the 150-MHz and 450-MHz frequency bands. Mostly, it is used for data links with

small distribution system remote terminal units (RTUs) that are not critical to power system operation and not economical to serve with a dedicated or dial phone line. More common usage of TWLM media is Multiple Address System (MAS) radio, which was developed specifically for SCADA applications.

(2) MAS essentially emulates telephone leased line circuits. The system consists of a transmitting master station and multiple remote stations using frequencies in the 900-MHz and above range. Its use is not practical for hydro plant data acquisition and control, but it should be considered if a hydrometeorological (hydromet) data system is to be built in the plant area, and hydromet data gathering controlled from the plant. It could also be considered for use in pumping plants that are under the surveillance of the plant staff.

g. Microwave radio.

(1) Microwave radio consists of transceivers operating at or above 1,000 MHz in either a point-to-point or point-multipoint mode. Microwave radio systems have both multiple voice channel and data channel capabilities. Microwave systems use either analog (Frequency Division Multiplex [FDM]) or digital (Time Division Multiplex [TDM]) modulating techniques. The trend is towards digital modulating systems because of increasing need for high speed data circuits and the superior noise performance of TDM modulation. Analog radio is considered to be obsolete technology, and it is likely that analog radio will not be available in the future.

(2) Microwave radio energy is transmitted in a "line of sight" to the receiving station, and the useful transmission path length varies depending on the frequency. Whether a microwave system can be used at all depends on factors beyond the scope of this manual, including the terrain features between end points of the system. However, in general it can be said that useful systems of any length will require one or more repeater stations located at such points on the radio path that they can be seen from the stations they receive from, and the stations they transmit to. Such repeater locations may be remote from any utility services, and in fact may not even be near a road. Site access, real estate acquisition, construction on the site, environmental impacts, and maintenance of the station need to be carefully considered before a final decision is made to use microwave communications. FIRMR requirements must also be considered.

(3) Microwave radio has found some short-range use in providing communication between the powerhouse and its switchyard, if the switchyard is located a mile or more away from the plant and the plant ground mat is not solidly connected to the substation ground mat. The danger of voltage rise on control and communication cables between plant and substation during fault conditions is well known. Microwave radio is particularly useful here in providing isolation from noise and dangerous voltage levels on these circuits, since with the radio there is no metallic connection between the terminals. Note, however, that a fiber-optic carrier system will also offer the advantages of a nonmetallic connection, and may be more economical.

(4) Generally, microwave radio transceiver equipment accommodations in the plant are handled in the same manner as PLC equipment accommodations. However, distance to the antenna, antenna location, and wave guide routing must be considered. The effects of icing on the antenna may require a power source for the antenna location to provide antenna heating.

h. Fiber-optic cable.

(1) A fiber-optic cable system consists of a terminal with multiplexing equipment, and a transmitter and receiver coupled to fiber-optic light conductors that are routed to the other terminal, which also has a receiver, transmitter, and multiplexing equipment. Because the transmission medium is nonmetallic, it offers the advantage of electrical isolation between terminals and immunity from electromagnetic interference.

(2) Because of the frequency of the transmitting medium, light, the fiber-optic system offers a bandwidth that can carry a great deal of data at very high speeds. The glass fibers are small and delicate, so should be enclosed in a protecting sheath. For communication systems external to the plant, right-of-way acquisition may be a problem since the fiber-optic cable does require routing just as a copper cable would.

(3) There are many possible ways of routing the fiber. It is possible to obtain high-voltage transmission line cable with fiber-optic light conductors incorporated in its construction. The fiber-optic light conductor can also be underbuilt on the transmission line to the plant. For long transmission distances, the fiber-optic system requires repeaters. The transmission distance before repeaters are needed has been steadily increasing because of the development effort in this technology. It offers great possibilities for external plant communication systems and should be considered in each case.

(4) Probably the most important application for fiber-optic technology is for a Local Area Network (LAN) within the plant. Its large data capacity, high rate of data transmission speed, and immunity from electromagnetic interference make the LAN an ideal medium for communication among the elements of distributed control systems within the plant. The technology is developing at a very rapid rate, and standards are coming into being, such as the Fiber Distributed Data Interface (FDDI), allowing its use with a variety of devices.

i. Satellite communications. Satellite communication systems have not been applied to Corps plants because of cost and convenience. The Corps has made use of a satellite time signal to provide a uniform time signal to plant control systems, but that signal is available to any suitable receiver without charge. Though this alternative appears to have many attractive advantages, the utility industry in general has yet to implement widespread use of private networks based on satellite technology.

10-4. Communication System Selection

a. Systems external to the plant. In most cases, the choice of the communications media used for dispatching and remote plant control and monitoring will not be a responsibility of the plant designer. The power-wheeling entity for the plant's power production will use systems and equipment compatible with the utility's "backbone" communications network. It is the plant designer's responsibility to ensure that adequate provisions are made for the communication system's terminal equipment and to ensure that plans and specifications prepared for powerhouse equipment and systems address special requirements for voice and data transmission as dictated by the external communication system. Coordination with the system owner will be required to ensure compatibility.

b. Design considerations. Other design considerations include interface requirements for data circuits, as imposed by the communication utility due to FCC regulations, and ground potential rise protection requirements for plant terminals of the metallic circuits used for voice, data, and control. In cases where the project scope includes development of a communications network, a comprehensive study should be made of alternatives available including system life-cycle costs to determine the most technically appropriate and cost-effective scheme to achieve successful communications system integration. EPRI EL-5036, Volume 13, provides guidance on criteria to evaluate if the project scope includes development of a communications network.

c. Internal plant communications. Internal data circuits (LANs) will be included with the data acquisition and control equipment that uses them, but the designer should consider that fiber-optic technology will probably be used. Also, for large plants to be staffed with administrative and maintenance personnel, a network of microcomputers may be added after the plant is in operation. The plant designer should provide facilities for routing network data highways between offices, maintenance shops, and the control room.

Chapter 11
Direct-Current System

11-1. General

A direct-current system is used for the basic controls, relaying, SCADA equipment, inverter, communication equipment, generator exciter field flashing, alarm functions, and emergency lights. The system consists of a storage battery with its associated eliminator-type chargers, providing the stored energy system required to ensure adequate and uninterruptible power for critical power plant equipment. The battery and battery circuits should be properly designed, safeguarded and maintained, and the emergency requirements should be carefully estimated to ensure adequate battery performance during emergencies. IEEE 946 and EPRI EL-5036, Volume 9, provide guidance about factors to consider and evaluate in planning and designing direct current systems. IEEE 450 provides guidelines and procedures for testing the capacity of the battery system.

11-2. Batteries

a. Type. The battery or batteries should be of the lead-acid type in vented cells or a sealed cell.

b. Battery room and mounting. A separate room or an area enclosed with a chain link fence with lockable doors provides adequate protection against accidental contact or malicious tampering. The room or area should be ventilated in such a manner that exhaust air from the room does not enter any other room in the plant. If necessary, heat should be provided to obtain full rated performance out of the cells. The cells should be mounted in rows on racks permitting viewing the edges of plates and the bottom of the cells from one side of the battery. The tops of all cells should preferably be of the same height above the floor. The height should be convenient for adding water to the cells. Tiered arrangements of cells should be avoided. Aisles should be provided permitting removal of a cell from its row onto a truck without reaching over any other cells. The lighting fixtures in the room should be of the vapor-proof type, with the local control switch mounted outside by the entrance to the room. Battery charging equipment and controls should not be located in the battery room. Thermostats for heater control should be of the sealed type, and no contactors or other arc-producing devices should be located in the battery room. A fountain eyewash-safety shower and drain should be provided in the battery room.

c. Number and sizes. The number and sizes of batteries depend upon the physical sizes of the initial and ultimate stages of plant construction and the loads to be carried by the battery system. A 58/60-cell battery (129-V) is adequate for a plant with four to six main units. Where a large plant has a considerable amount of emergency lighting, long circuits, and a high number of solenoid loads, a 116/120-cell battery may be warranted.

d. One- or two-battery systems. If the ultimate plant will have a large number of generating units, studies should be made to determine whether one control battery for the ultimate plant will be more desirable and economically justifiable instead of two or more smaller batteries installed as the plant grows. Selection of a one- or two-battery system will depend not only on comparative costs of different battery sizes and combinations, including circuits and charging facilities, but consideration of maximum dependability, performance, and flexibility during periods of plant expansion.

e. DC load. The recommended procedure for determining the proper battery rating is outlined in IEEE 485. The standard classifies the total DC system load into the following categories:

(1) Momentary loads. Momentary loads consist of switchgear operations, generator exciter field flashing, voltage regulators, and similar devices. Momentary loads are assumed to be applied for 1 min or less.

(2) Noncontinuous loads. Noncontinuous loads consist of emergency pump motors, fire protection systems, and similar systems. Noncontinuous loads are those only energized for a portion of the duty cycle.

(3) Continuous loads. Continuous loads consist of indicating lamps, inverters, contactor coils, and other continuously energized devices. Continuous loads are assumed to be applied throughout the duty cycle.

f. Emergency loads. In cases where emergency lighting is excessive, the emergency load should be broken down into two separate loads:

(1) Thirty-minute emergency load. The 30-min emergency load consists of emergency lights that can be conveniently disconnected from the DC system when the location of the trouble has been determined.

(2) Three-hour emergency load. The 3-hr emergency load consists of the emergency lights required after the trouble area has been determined.

g. Battery capacity. Using the above load classes and durations and battery data obtained from manufacturer's literature, a station battery duty cycle is determined (see IEEE 485). The battery capacity required is determined as the sum of the requirements for each class and duration of load comprising the duty cycle.

h. Battery and accessory purchase. The batteries, with their accessories, indicating cell connectors, hydrometers, cell number, etc., are normally purchased through the GSA Schedule. Standard battery racks for the battery installation may also be obtained through GSA Schedules.

i. Safety considerations. Standard rack performance criteria should be evaluated to ensure compliance with plant requirements. Seismic considerations and other factors may dictate the need for special racks and special anchoring needs. The racks, anchors, and installation practices, including seismic considerations, are discussed in IEEE 484 and IEEE 344. Electrical safety considerations for battery installations are covered in Article 480 of the National Electrical Code (NFPA 70).

11-3. Battery-Charging Equipment

Static charger sets are preferred for battery-charging service. Two sets should be provided so one will always be available. The charger capacity should be sufficient for supplying the continuous DC load normally carried while recharging the station battery at a normal rate. The chargers should be of the "battery eliminator" type (additional filtering) allowing them to carry station DC loads while the battery is disconnected for service. The battery-charger systems should be located near the battery room, usually in a special room with the battery switchboard and the inverter sets. Standard commercial features and options available with station and communication battery chargers are outlined in NEMA PE5 and PE7.

11-4. Inverter Sets

One inverter set should be provided in all plants where it is necessary to maintain a continuous source of 120-V AC. A separate supply bus for selected 120-V AC single-phase feeder circuits should be provided for SCADA, recording instrument motors, selsyn circuits, and communication equipment. A transfer switch should be provided to automatically transfer the load from the inverter output to the station service AC system feeder in case of inverter failure. Standard commercial features and options available with inverters used in uninterruptible power supplies are outlined in NEMA PE1.

11-5. Battery Switchboard

Battery breaker, DC feeder breakers, ammeters, and ground and undervoltage relays should be grouped and mounted in a battery switchboard.

Chapter 12
Lighting and Receptacle Systems

12-1. Design

a. General. For the purposes of design and plan preparation, the lighting system is defined as beginning with the lighting transformers and extending to the fixtures. This facilitates design coordination of various features of the lighting system. For purposes of discussion, it also covers 480-V and 120-V convenience outlets and corresponding circuits. After the design is complete, the system may be broken down into separate categories as determined by how the equipment will be obtained and installed in the construction stage. One method of handling the division of work is outlined below. The lighting systems, including fixtures and receptacles, are normally furnished and installed by the powerhouse contractor.

b. Conduit and cable schedule. Supply cables and conduit to transformers and lighting panels should be listed in the conduit and cable schedule. Branch circuits are normally not included on the schedule.

c. Panels. Lighting panels should be designed for the job, using air circuit breakers to protect the branch circuits, and should be purchased and installed by the general contractor.

d. Distribution center. In designing the lighting distribution system, several schemes should be considered, and a scheme adopted which gives the lowest overall cost without sacrificing simplicity of design or efficiency of operation. Two general schemes are:

(1) Small plant. A centrally located lighting transformer supplying the entire plant, which may be either:

(a) A 480-120/240-V, single-phase transformer with 120/240-V feeders and branch circuits.

(b) A 480-120/208-V, 3-phase, 4-wire transformer with 120/208-V feeders and branch circuits.

(c) A 480-480Y/277-V, 3-phase, 4-wire transformer with 480Y/277-V feeders and branch circuits.

(2) Large plant. Transformers located near the load centers and fed by individual supply feeders from the station service switchgear to supply lighting for a local area, each transformer being either:

(a) A 480-120/240-V, single-phase transformer, feeding panels with 120/240-V branch circuits.

(b) A 480-120/208-V, 3-phase, 4-wire transformer, feeding panels with 120/208-V branch circuits.

(c) A 480-480Y/277-V, 3-phase, 4-wire transformer, feeding panels with 480Y/277-V branch circuits.

12-2. Illumination Requirements

a. Intensity level. The lighting system should be designed to give the maintained-in-service lighting intensities recommended by the IES Handbook (Kaufman 1984). A maintenance factor of 0.75 is considered appropriate for a well-maintained project.

b. Emergency lighting. Emergency lighting should be designed to light important working areas within the powerhouse and should be adequate to provide safe passage between such areas with a minimum load on the station battery. NFPA 101 provides guidance on areas requiring emergency lighting for personnel safety. Self-contained, battery-operated, emergency lighting systems should be considered to lower capacity requirements on the station battery. Self-contained, battery-operated systems should be employed in areas with minimal occupancy or personnel access following an event initiating use of the emergency lighting system. Emergency lighting for control rooms, unit control switchboard areas, station service switchgear areas, the emergency generator area, and interconnecting passageways between these areas should be powered by the station battery.

c. Exterior lighting. Exterior lighting should be provided for the switchyard, parking areas, passageways near the powerhouse, the draft tube deck, and for the upstream deck if there is one. Flood-lighting of the outside powerhouse walls should be included in the original design, with provisions made for extension of lighting circuits if the floodlights are not initially installed. Exterior doorways should be lighted either by flush soffit lights or by bracket lights. If bracket lights are used, they should be selected to enhance the architectural appearance of the doorways.

d. Specific conditions. For general areas, the zonal cavity method of illumination design (see IES Handbook) is considered satisfactory. For special conditions such as illumination (Kaufman 1984) of the vertical surfaces of switchboards, a careful check by the point-by-point method may be needed. Care should be taken to minimize reflected glare from the faces of switchboard instruments. To facilitate design review, the manufacturer's candlepower distribution curves should accompany the design drawings. If fixtures of unusual design are being specified, their use must be justified, with complete details of the fixtures submitted with the lighting design data.

e. Evaluation. Evaluation and choice of lighting systems should consider both energy and maintenance costs as well as initial cost of the fixtures.

12-3. Efficiency

a. General. Energy conservation is an important concern when designing lighting systems. In the powerhouse, use of high efficiency lighting has the potential for saving significant amounts of energy. An efficient lighting system is one in which the required amount of light reaches the area to be illuminated at the proper level and color, while using the minimum amount of energy. The well-designed lighting system should make maximum use of available natural light and consider the direction of light and the desired dispersion or focus. Encouraging efficient use requires provision of convenient control points, use of proximity detectors in unoccupied interior spaces, and consideration of two-level lighting in low-occupancy machinery areas.

b. Lighting source types. Efficient light sources should be considered. There are four common lighting source categories, as follows:

(1) Incandescent. In general, incandescent lamps provide the "whitest" light, but at a higher energy cost and relatively short life. Incandescent lamps are used where fluorescent fixtures are not practical for reasons of vapor, limited space, high lighting levels, or the need for superior color rendition.

(2) Fluorescent. Triphosphor fluorescent lamps are a good source of "white" light and are relatively long-lived, with energy efficiencies better than incandescent lamps. Most rooms and shops should be illuminated with energy-efficient, fluorescent fixtures, using T-8 high-efficiency lamps and electronic ballasts.

(3) High-intensity discharge (HID).

(a) HID mercury lamps are fairly efficient, have relatively long lives, but are not a good source of "white" light, covering only about 50 percent of the visible spectrum.

(b) HID metal halide lamps are a good source of "white" light, covering about 70 percent of the visible spectrum. They have good life and are very efficient. Their disadvantages are relatively long start and restart times.

(c) HID high pressure sodium lamps are very efficient, but are a poor source of "white" light, covering only about 21 percent of the available spectrum. They need about 3 or 4 min of start time, and about 1 min of restart time.

(4) Low-pressure sodium (LPS). LPS lamps are the most efficient lamps available, but produce almost no "white" light, so their use is extremely limited. They have long lives, short start times, and very short restart times.

c. Evaluation. When designing the lighting system, all of the above sources should be considered and the most efficient combination of sources used, appropriate with achieving design lighting levels and good lighting quality. Evaluation and choice should consider both energy and maintenance costs, as well as initial cost of the fixtures. EPRI TR-101710 provides guidance on achieving design lighting levels in an energy-efficient, cost-effective manner.

12-4. Conductor Types and Sizes

The voltage drop in panel supply circuits should be limited to 1 percent if possible, and the drop in branch circuits should be limited to 2 percent. If it is not possible to limit the voltage drop to these figures, a limit of 3 percent for the total voltage drop should be observed. In arriving at the voltage at the load, the impedance drop through the transformer should be considered, although this drop need not be considered in feeder or branch circuit design. Branch circuit and panel feeder design should be based on the considerations outlined in Chapter 15. Minimum conduit size should be 3/4 in. and the minimum conductor size should be No. 12 AWG.

12-5. Emergency Light Control

A system employing selected fixtures normally supplied from the AC source through an automatic transfer switch transferring the fixtures to the DC system on AC voltage failure should be provided. Fixtures sourced from the station battery should be minimized to reduce battery drain (see paragraph 12-2*b*). Return to the AC source should be automatic when the AC source is restored.

12-6. Control Room Lighting

a. General. Many different schemes have been used in attempting to develop "perfect" control room lighting. This emphasis is due to the difficult and continuous visual tasks that are performed in the control room. Task ambient lighting provides the most effective approach to achieving desired results. IES-RP-24 provides guidance on topics such as quality of illumination, luminance levels, and the visual comfort of room occupants, which must be evaluated in developing a control room lighting design.

b. VDTs and instrument faces. Plant control systems use visual display terminals (VDTs) which tend to "wash out" in high ambient lighting, and the VDT face reflects light from sources behind the operator that make the screen image unreadable. Switchboard instrument faces also reflect light, and such reflections obscure the instrument dial. Light fixtures or window areas should not be reflected by the instrument glass and VDT screen.

c. Switchboard lighting. Switchboards should be lighted so that the instrument major scale markings and pointers can be readily seen from the control console even though the actual numbers opposite these markings cannot be read. Sufficient vertical illumination on the fronts of the boards is only part of the answer. Illumination must be provided in a manner that does not produce glare from the instrument glass, or objectionable shadows on the instrument face from the instrument rims and control switches. It is also important that no light source be visible in the line of the operator's vision when viewing the boards.

d. Lighting criteria. Extreme contrasts in lighted areas, such as a bright ceiling or wall visible above the switchboard, must be avoided, as they produce eye strain. The modern practice of using light-colored switchboards, and the latest design of indicating instrument dials have both helped to improve control room lighting. Good control room lighting will be obtained if the following criteria are observed:

(1) Adequate vertical illumination on vertical board surfaces.

(2) Brightness contrasts preferably within a ratio of 1 to 3. (No light sources in line of vision).

(3) No specular reflection from instrument, VDT screen, or other surfaces.

(4) No objectionable shadows on working surfaces.

e. Heat. The amount of heat from the lamps (of any type) in the control room must be given special consideration in designing the air-conditioning layout for the control room and adjacent areas.

12-7. Hazardous Area Lighting

Battery room and oil room fixtures should be vapor- and explosion-proof type, and local control switches should be mounted outside the door. Lighting switches of the standard variety may be used by placing them outside the room door. Convenience receptacles in the rooms should be avoided, or where necessary, be of the explosion-proof type.

12-8. Receptacles

The types and ratings of receptacles for convenience outlets should be clearly indicated on the fixture and device schedule sheet in the drawings, or in the bill of materials. Standardization of receptacles allows use of portable equipment throughout the project. The following receptacles are suggested as the appropriate quality and type:

a. 480-V receptacles. 3-wire, 4-pole, 30 A, grounded through extra pole and shell of plug type receptacles are recommended. The receptacles and plugs should meet the requirements of ANSI/UL 498 and should be weather resistant for use in wet and dry locations. For welding machines and other portable 480-V equipment, use two-gang-type cast boxes to ensure adequate room for No. 6 AWG feeders, except for the placement of 480-V receptacles at the end of conduit runs, which may be single-gang receptacles.

b. 120-/208-V receptacles. 4-wire, 5-pole, 30 A, grounded type receptacles, plugs, and fixtures meeting the requirements of ANSI/UL 498 and 514 are recommended. Typically, these fixtures are used to service supplemental lighting in work areas during overhauls.

c. 120-V receptacles. The choice between using a twist-lock receptacle or using a parallel-blade receptacle has never been standardized nationwide. There is a trend to employ parallel-blade receptacles on new construction projects. Parallel-blade receptacles are recommended unless there is a strong local preference for twist-lock receptacles based on existing local standardization. Ground fault protection should be provided for 120-V outlets in all wet locations or outdoors. Use appropriate ground fault interrupter circuit breakers in these locations.

(1) Twist-lock receptacles. For projects using twist-lock receptacles, 3-pole, 15-A, 125-V, grounding, duplex, twist-lock, NEMA L5-15R configuration for use with compatible twist-lock caps are recommended for dry locations within all powerhouse areas. For wet locations or outdoors, a similar single-gang receptacle in a cast box with twist-lock caps or plugs is recommended. For lunch rooms, office areas, lounges and restrooms, duplex combination, twist-lock, straight-blade receptacles, NEMA L5-15R configuration, are recommended.

(2) Straight-blade receptacles. For projects using straight-blade receptacles, 3-pole, 20-A, 120-277-V grounding, duplex, hospital grade, NEMA 5-20R configuration, are recommended for dry locations. For wet locations or outdoor use, single, hospital-grade receptacles in the same configuration, with weatherproof single-receptacle cover plates are recommended.

Chapter 13
Grounding Systems

13-1. General

a. Purpose. A safe grounding design has two objectives: to carry electric currents into earth under normal and fault conditions without exceeding operating and equipment limits or adversely affecting continuity of service and to assure that a person in the vicinity of grounded facilities is not exposed to the danger of electric shock.

b. Reference. IEEE 142, known as "The Green Book," covers practical aspects of grounding in more detail, such as equipment grounding, indoor installations, cable sheath grounding, etc. This standard provides guidance in addressing specific grounding concerns. Additional guidance for powerhouse-specific grounding issues is provided in EPRI EL-5036, Volume 5.

13-2. Safety Hazards

The existence of a low station ground resistance is not, in itself, a guarantee of safety. During fault conditions, the flow of current to earth will produce potential gradients that may be of sufficient magnitude to endanger a person in the area. Also, dangerous potential differences may develop between grounded equipment or structures and nearby earth. IEEE 80 provides detailed coverage of design issues relating to effective ground system design. It provides a detailed discussion of permissible body current limits and should be reviewed prior to developing a grounding design. It is essential that the grid design limit step and touch voltages to levels below the tolerable levels identified in the standard. The conditions that make electric shock accidents possible are summarized in Chapter 2 of the guide and include:

a. High fault current to ground in relation to the area of ground system and its resistance to remote earth.

b. Soil resistivity and distribution of ground currents such that high potential gradients may occur at the earth surface.

c. Presence of an individual such that the individual's body is bridging two points of high potential difference.

d. Absence of sufficient contact resistance to limit current through the body to a safe value.

e. Duration of the fault and body contact for a sufficient time to cause harm.

13-3. Field Exploration

After preliminary layouts of the dam, powerhouse, and switchyard have been made, desirable locations for two or more ground mats can be determined. Grounding conditions in these areas should be investigated, and the soil resistance measured. IEEE 81 outlines methods for field tests and formulas for computing ground electrode resistances. Sufficient prospecting should be done to develop a suitable location for the ground mat coupled with a determination of average soil resistivity at the proposed location. IEEE 81 describes and endorses use of "the Wenner four-pin method" as being the most accurate procedure for making the soil resistivity determination. It also provides information on other recognized field measurement techniques.

13-4. Ground Mats

a. General requirements. The measured soil resistivity obtained by field exploration is used to determine the amount of ground grid necessary to develop the desired ground mat resistance. The resistance to ground of all power plant, dam, and switchyard mats when connected in parallel should not exceed, if practicable, 0.5 ohm for large installations. For small (1500 *kW*) plants, a resistance of 1 ohm is generally acceptable. Practical electrode drive depth should be determined in the field. A depth reaching permanent moisture is desirable. The effective resistance of, and the step and touch potentials for, an entire ground mat with a number of electrodes in parallel can be determined from IEEE 80. The diameter of the electrode is determined by driving requirements. Copper-weld ground rods of 3/4 in. diam are usually satisfactory where driving depths do not exceed 10 ft. For greater depths or difficult soil conditions, 1-in.-diam rods are preferred. Galvanized pipe is not suitable for permanent installations.

b. Location. The depth and condition of the soil upstream from the dam on the flood plain is frequently favorable for placement of one or two ground mats. These can be used for the grounding of the equipment in the dam and leads extended to the grounding network in the powerhouse. At least one ground mat should be provided under or near the switchyard.

c. Leads. Leads from ground mats should be sufficiently large to be mechanically durable, and those which may carry large fault currents should be designed to minimize IR drop. Two leads, preferably at opposite ends of the mat, should be run to the structure or yard, and the entire layout designed to function correctly with one lead disconnected. The design and location of connecting leads should account for construction problems involved in preserving the continuity of the conductor during earth moving, concrete placement, and form removal operations.

d. Types of ground mats. Topography of the site, soil conditions, and depth of soil above bedrock are factors influencing not only the location, but type of ground mat used. Some common types (in addition to forebay location) are:

(1) Ground rods driven to permanent moisture and interconnected by a grid system of bare, soft annealed copper conductors. This type of mat is preferable.

(2) A grid of interconnected conductors laid in trenches dug to permanent moisture below the frost line.

(3) Ground wells with steel casings used as electrodes, or holes in rock with inserted copper electrodes and the hole backfilled with bentonite clays. The wells or holes should penetrate to permanent moisture.

(4) Plate electrodes or grids laid in the powerhouse tailrace, suitably covered or anchored to remain in place.

e. Ground resistance test. A test of the overall project ground resistance should be made soon after construction. Construction contract specifications should contain provisions for adding ground electrodes if tests indicate that this is necessary to obtain the design resistance. Proper measurement of the resistance to ground of a large mat or group of mats requires placement of the test electrodes at a considerable distance (refer to IEEE 81). Transmission line conductors or telephone wires are occasionally used for test circuits before the lines are put into service.

13-5. Powerhouse Grounding

a. Main grounding network.

(1) This network should consist of at least two major runs of grounding conductors in the powerhouse. Major items of equipment such as generators, turbines, transformers, and primary switchgear should be connected to these grounding “buses” so there are two paths to ground from each item of equipment.

(2) Copper bar rather than cable is preferred for exposed runs of bus. Generator leads of the metal-enclosed type will be equipped by the manufacturer with a grounding bar interconnecting all bus supports. Properly connected, this forms a link in the powerhouse ground bus.

(3) In selecting conductor sizes for the main grounding network, three considerations should be borne in mind:

(a) The conductors should be large enough so that they will not be broken during construction.

(b) Current-carrying capacity of the conductors should be sufficient to carry the maximum current for a fault to ground for a minimum period of 5 sec without damage to the conductor (fusing) from overheating.

(c) The total resistance of the loads from major items of equipment should be such that the voltage drop in the cable under fault conditions will not exceed 50 V.

b. Equipment. Miscellaneous electrically operated equipment in the powerhouse should be grounded with taps from the main ground network. For mechanical strength, these conductors should be not less than No. 6 AWG. The resistance of these taps should keep the voltage drop in the leads to the ground mat to less than 50 V. They should carry the current from a fault to ground without damage to the conductor before the circuit protective device trips. Provisions should be made in the design of the powerhouse grounding system for bare copper cable taps of sufficient length to allow connection to equipment installed after installation of the grounding system. Generally, the tap connection cable is coiled in a concrete blockout for easy accessibility later when attaching the tap to the housing of the equipment with pressure connectors. Items of minor equipment may be grounded by a bare wire run in the conduit from the distribution center to the equipment. The neutrals and enclosures of lighting and station service power transformers should be grounded. Distribution center and lighting panel enclosures as well as isolated conduit runs should be grounded.

c. Conductor size selection. Ground conductor sizes should be limited to Nos. 6, 2, 2/0, 250 kCM and 500 kCM, or larger, to limit ordering inventories and access normally stocked conductor sizes. Subject to short-circuit studies, usage, in general, is as follows:

(1) No. 6: Control cabinets, special outlets, machinery, lighting standards, power distribution equipment with

main feeders #2 or less, and motor frames of 60 *hp* or less.

(2) No. 2: Switchboards, governor cabinets, large tanks, power distribution equipment with primary or secondary feeders 250 kCM or less, and motor frames between 60 and 125 *hp*.

(3) No. 2/0: Roof steel, crane rails, generator neutral equipment, gate guides, power distribution equipment with primary or secondary feeders larger than 250 kCM, and motor frames larger than 125 *hp*.

(4) 250 kCM: Turbine stay-rings, turbine pit liners, generator housings and/or cover plates, large station service transformers, transmission tower steel, and interconnecting powerhouse buses.

(5) 500 kCM: Main powerhouse buses, leads to the ground mat, generator step-up transformer grounds, and surge arrester grounds.

(6) 750-1,000 kCM: Main powerhouse buses or leads to the ground mat when larger sizes are needed.

d. Miscellaneous metal and piping. Powerhouse crane rails should be bonded at the joints with both rails being connected to ground. Roof trusses; draft tube gate guides; and miscellaneous structural steel, which may be exposed to dangerous potentials from energized circuits, should be connected to the ground network. All piping systems should be grounded at one point if the electrical path is continuous, or at more points if the piping system's electrical path is noncontinuous.

13-6. Switchyard Grounding

a. Copper conductors. A grid of copper conductors should be installed beneath the surface of the switchyard to prevent dangerous potential gradients at the surface. The cables should be large enough and be buried deep enough for protection from mechanical damage. The cables' current-carrying capacity under fault conditions and during lightning discharges should be checked. Under all conditions, the grid serves to some extent as an electrode for dissipating fault current to ground.

b. Ground rods. If warranted by soil conditions, a system of ground rods should be installed with the grid to provide maximum conductance to ground.

c. Grounding platform. A grounding platform consisting of a galvanized steel grating set flush in the gravel surfacing or a grounding mesh buried 12-18 in. below grade should be provided at each disconnecting switch handle. The platform or mesh should be grounded to the steel tower and to the ground network in two places.

d. Grounded equipment. Grounded switchyard equipment includes tanks of circuit breakers, operating mechanisms of disconnecting switches, hinged ends of disconnect grounding blades, transformer tanks and neutrals, surge arresters, cases of instrument transformers and coupling capacitors, and high-voltage potheads. Isolated conduit runs, power and lighting cabinet enclosures, and frames of electrically operated auxiliary equipment should also be grounded. Separate conductors are used for grounding surge arresters to the ground network. Fences, including both sides of any gates, and other metal structures in the switchyard, should be grounded to the switchyard grid at intervals of about 30 ft. If the fence gates open outward, a ground conductor shall be provided approximately 3 ft outside the gate swing radius. Each switchyard tower should be grounded through one leg. All structures supporting buses or equipment should be grounded. If the network does not extend at least 3 ft outside the fence line, separate buried conductors should be installed to prevent a dangerous potential difference between the ground surface and the fence. These conductors should be connected to both the fence posts and the ground network in several places.

e. Overhead ground wires. Overhead ground wires should be bonded securely to the steel structure on one end only and insulated on the other to prevent circulating current paths.

13-7. Grounding Devices

a. Cables. Grounding cable used for direct burial or embedding in concrete should be soft-drawn bare copper. Sizes larger than No. 6 AWG should be stranded.

b. Electrodes. Electrodes for driving should be copper-weld rods of appropriate diameter and length. Desired lengths can be obtained on factory orders.

c. Exterior connections. Ground cable connections to driven ground rods, any buried or embedded connections, or any exposed ground grid connections should be made either with an appropriate molded powdered metal weld or by a copper alloy brazed pressure connector.

d. Interior connections. Pressure clamp (bolted) type terminal lugs should be used for interior work. For neatness of appearance of interior connections, embedded grounding cables may terminate on or pass through grounding inserts installed with the face of the insert flush with the finished surface. Connection to the apparatus is made by bolting an exposed strap between a tapped hole on the insert and the equipment frame.

e. Test stations. Test stations should be provided for measuring resistance of individual mats and checking continuity of interconnecting leads. Where measurements are contemplated, the design of the grounding systems should avoid interconnection of ground mats through grounded equipment, overhead lines, and reinforcing steel.

f. Embedded cable installation. Embedded ground cables must be installed so movement of structures will not sever or stretch the cables where they cross contraction joints. Suitable provision should be made where embedded cables pass through concrete walls below grade or water level to prevent percolation of water through the cable strands.

g. Conduit. Grounding conductors run in steel conduit for mechanical protection should be bonded to the conduit. Control cable sheaths should be grounded at both ends. Signal cable shields are grounded at one end only.

Chapter 14
Conduit and Tray Systems

14-1. General

The conduit and tray system is intended to form a permanent pathway and to provide maximum protection for the conductors. The system design should allow for reasonable expansion of the number of leads and circuits.

14-2. Conduit

a. Design. Where practicable, all conduits should be concealed. In cases in which allowance must be made for circuits to future equipment, the conduit extension may be exposed. Connections to equipment should not be made with flexible conduit if suitable connections can be made with rigid conduit.

(1) Conduit size is determined by the type of wire and number of circuits in the run, the length of run and the number and degree of bends in the run.

(2) Where conduits cross building contraction joints, the conduit runs should be perpendicular to the joint and expansion fittings, such as dresser couplings with grounding straps, installed to provide for movement of the conduit and to maintain an unbroken ground path. The fitting, installed on one side of the contraction joint, should be protected with a suitable neoprene sleeve to accommodate differential movement of the concrete.

(3) Conduit should be installed in a manner to permit condensed water to drain whenever possible. When self-draining is not possible, a suitable drain should be installed in the low point of the run. Threaded joints in metal conduit and terminations in cast boxes should be coated with an approved joint compound to make the joints watertight and provide electrical continuity of the conduit system.

(4) The conduit should provide a ground for the frames or housings of equipment to which it is connected, thereby providing a backup for the ground wire connection to the main grounding system. All conduits except lighting branch circuit conduits should be listed in the conduit and cable schedule.

b. Conduit types.

(1) Rigid steel conduit should be hot-dip galvanized on inside and outside surfaces, conforming to ANSI C80.1.

(2) For powerhouse substructure work, if conditions are such that embedded galvanized conduit might rust out, consideration should be given to installing exposed runs which can be replaced. Galvanized conduit buried in the switchyard should be protected with a coat of bituminous paint or similar material, unless experience at the particular site has demonstrated that no special protection is needed on the galvanized conduit.

(3) Unjacketed type MC or type MV cables, meeting the requirements of UL 1569 or UL 1072, may be used to avoid installing a cable tray carrying only a few conductors or where the installed cost would be substantially less than installing rigid steel conduit. Compatible connectors should be used to bond the sheath to the ground system and to the equipment served. The copper sheath version is preferable for corrosive environments. MC or MV cables with PVC insulation or jacketing should not be used.

c. Boxes and cabinets.

(1) The materials used for boxes and cabinets should conform to those used for the conduit system. Cast iron boxes should be used with galvanized conduit in embedded and exposed locations at and below the generator room floor level. Galvanized sheet steel boxes are acceptable in locations above the generator room floor. Suitable extension rings should be specified for outlet boxes in walls finished with plaster or tile. Large cabinets used for pull boxes, distribution centers, and terminal cabinets are usually constructed of heavy-gauge, galvanized sheet steel. Because it is impracticable to galvanize large sheet metal boxes and fronts after fabrication without severe warping, galvanized steel sheets should be used in the fabrication. Box corners should be closed by welds after bending, and the galvanizing repaired by metallized zinc spray.

(2) If a cabinet is embedded in a wall finished with plaster or tile, special precautions should be observed to ensure that the face of the installed cabinet is flush with

the finished wall. Front covers are generally mounted with machine screws through a box flange drilled and tapped in the field to facilitate proper alignment. The requirements of UL 50 should be considered as minimum in the design of such cabinets. Provision should be made for internal bracing of large cabinets to prevent distortion during concreting operations.

(3) Pull boxes for telephone circuits should be large enough to provide adequate space for fanning-out and connecting cables to the terminal blocks.

14-3. Cable Trays

a. General. Cable trays are commonly used to carry groups of cables from generating units, the switchyard, and accessory equipment that terminates in the control room. Trays in place of conduit provide flexibility, accessibility, and space economy. Trays are also used for the interconnecting cables between switchboards in the control room, and from switchboards to the terminations of embedded conduits running to equipment. Short runs of trays may be used to connect two groups of conduit runs where it is not practicable to make the conduit runs continuous. The designed tray system should provide the maximum practicable segregation between control circuits and power and lighting circuits. Appropriate guidelines for cable tray design considerations are contained in IEEE 422.

b. Fabrication. Cable trays are fabricated from extruded aluminum, formed sheet metal, or expanded metal. Material costs for the expanded metal trays may be slightly higher, but a greater selection of joining devices, greater distance between supports, and special sections and fittings minimize field labor costs and generally result in lowest installed cost.

c. Tray supports. The trays are installed on fabricated galvanized steel supports designed and anchored to the powerhouse walls and/or ceiling to provide a rigid structure throughout. In the cable spreading room, the tray supports may extend from the floor to the ceiling to give the necessary rigidity. Supports similar to cable racks and hooks are suitable for supporting cable trays on cable tunnel walls. If trays run through the center of a tunnel, they should be supported on structural members such as channel with angle cross-pieces. Metal tray sections 8 ft long require supports on 8-ft centers. Splices should be made at supports to provide proper anchorage for the tray sections.

d. Cable supports. Split hardwood blocks drilled to fit cables or accessories for the metal trays should be provided as necessary to support cables entering and leaving the trays. The tray system should be designed to avoid long steep runs requiring anchoring of the cables to prevent movement.

Chapter 15
Wire and Cable

15-1. General

Wire and cable systems should be designed for long life with a minimum of service interruptions. The materials and construction described in Guide Specification CW-16120 provide construction materials consistent with these service requirements. IEEE 422 provides overall guidance in planning, designing, and installing wire and cable systems in a power plant. Topics covered in the IEEE guide include cable performance, conductor sizing, cable segregation systems, installation and handling, acceptance testing, and other related subjects. Additional guidance is provided in EPRI EL-5036, Volume 4.

15-2. Cable Size

The minimum size of conductor for current-carrying capacity should be based on the National Electrical Code (NEC) requirements for 60 °C insulated wire. NEMA WC50 and WC51 provide ampacities for high-voltage cables and for multiconductor cables not covered in the NEC. Circuit voltage drop should be checked to ensure the total drop from the source to the equipment does not exceed requirements of Articles 210 and 430 of the NEC.

15-3. Cable System Classification

All cables or conductors, except lighting system branch circuits, should be listed in the conduit and cable schedule under the appropriate heading as either power or control cable. Design of the cable systems is divided into three classifications according to functions, as follows:

a. Interior distribution.

(1) Power and lighting conductors include circuits from the station service switchgear to distribution centers or to station auxiliary equipment; branch circuits and control circuits from distribution centers to auxiliary equipment; feeders to lighting panels; and lighting branch circuits. No conductor size smaller than No. 12 AWG should be used, except for control circuits associated with heating and air-conditioning equipment where No. 14 is adequate.

(2) Multiconductor power cables should be used for the larger and more important circuits such as feeders to distribution centers in the dam, the powerhouse, and the switchyard; lighting panels; and any other major project loads. Single-conductor wires can be used for branch circuits and control circuits from distribution centers to equipment when installed in conduit. For cable tray installations, Article 318 of the National Electric Code (NFPA 70-1993) dictates the use of multi-conductor tray rated cable for all circuits requiring No. 1 cable or smaller.

b. Control and communication.

(1) Control cables include station control and annunciator circuits from the control room switchboards, unit instrument boards, exciter cubicles, and secondary control centers. Such circuits are generally identified with the DC control system, the instrument bus, or the annunciator system. All control cables, except those for the communication system and special circuits noted in paragraph 15-3*b*(6), should comply with the requirements of Guide Specification CW-16120.

(2) The cables should be adequately supported in long vertical runs and where they enter or leave the cable trays. Multi-conductor cables are usually No. 19/25 or 19/22 for control, metering, and relaying circuits and No. 16 stranded for annunciator circuits. All current transformer secondary circuits should be No. 19/22 or larger. Larger conductor sizes may be required to take care of voltage drop, or to decrease the burden on instrument transformers.

(3) No splices should be made between the terminal points of the cable.

(4) In selecting cables, consideration should be given to minimizing the number of different cable items ordered for installation or stocked for maintenance. For example, the 4-, 6-, and 8-conductor cables might be omitted and 5-, 7-, and 9-conductor cables substituted, leaving one spare conductor. The practice of including one or more spare conductors in each cable of more than four conductors is considered desirable. Selection of sizes and numbers of conductors per control cable should be limited, if possible, to combinations that have 50 ft or more in each item of a lot ordered.

(5) All wiring for the telephone system, including circuits from the main cabinet to the local telephone jacks, should be listed under “Telephone” cables in the schedule. Selection of telephone system conductors will be dictated by the application.

(6) Special circuits such as calibrated ammeter leads, and coaxial cable circuits to carrier-current capacitors, computer networks, microwave, and video, should be

scheduled under control cables or telephone cables, whichever is applicable. Clarifying remarks concerning the type of the conductor and the supplier should be included. Where fiber-optic cables are used, installation and application should follow the manufacturer's recommendations. Two-conductor No. 19/25 control cables may be used where the circuit lengths make it impractical to obtain calibrated leads with the instruments.

(7) Analog and digital signal cables. There is no standard specification for these cables. There are general guidelines that should be followed in selecting the general characteristics of the signal cable to be used. Some of these guidelines are:

(a) PVC insulation or jacketing may not be used.

(b) Insulation and jacket material should pass UL flame tests.

(c) Analog signal conductors must be paired and twisted together with a shield, signal conductor, and return conductor in the same pair.

(d) Conductor pairs should be twisted, variable lay, pairs individually shielded.

(e) Multipair cables should have an overall shield and an outer jacket.

(f) Shields should be grounded at one end only to prevent shield current.

(g) Conductor size should be not less than No. 18 AWG.

(h) Minimum insulation level should be 150 V.

c. Grounding conductors. Embedded grounding system conductors should be stranded, soft-drawn, bare copper wire following the recommendations of Chapter 13. The cables need not be scheduled, but if brought out in test stations, should be suitably tagged for future identification.

15-4. Conduit and Cable Schedules

a. General. The intent of the conduit and cable schedule is to provide all pertinent information to assist in installing, connecting, identifying, and maintaining control and power cables. When not included with the plans for construction bids, the specifications indicate cable schedules will be furnished to the contractor.

b. Power circuits.

(1) Each cable and conduit should be identified with an individual designation. The cable and conduit are tagged with a designation at each end and at intermediate points as necessary to facilitate identification. The designation is also shown on equipment wiring diagrams, tray loading diagrams, on conduit plans and details, on cabinet layouts, and on junction and pull box layouts.

(2) The scheduling of cables should always include (opposite the cable designation) the following information:

(a) Number and size of conductor.

(b) Function or equipment served.

(c) Origin and destination.

(d) Routing via conduits and trays.

(e) Special conditions.

(f) Estimated length.

(3) The scheduling of conduit should include (opposite the conduit designation) the following:

(a) Size and type of conduit.

(b) Function or equipment serviced.

(c) Origin and destination.

(d) Special conditions.

(e) Length.

(4) Conduit and cable should have the same designation if possible. The number assigned should give information about the service rendered by the cable, the termination points of the cable, and the approximate voltage or power classification.

(5) Generally, each cable between major units of equipment or from major units of equipment in the powerhouse to structures external to the powerhouse is assigned a number made up of three parts, as follows:

(a) The first part of the cable number shows the beginning of each cable run and is composed of uppercase letters and numerals assembled into a code to represent the various major units of equipment, switchgear, switchboards, cabinets, etc., located throughout the powerhouse.

(b) The second part of the cable number is composed of a single lower-case letter and number. The letter indicates the type of service rendered by the cable, i.e., power, alarm, etc., while the number serves to differentiate between cables of a particular type running between two points.

(c) The third part of the cable number shows the termination of each cable run and is composed in the same manner as the first part of the cable number.

Example: Cable Number

Cable ID: SC-u3-G1

Breakdown: SC = Start of cable run (Main control switchboard)
u = Type of service (Annunciator lead)
3 = Number of such cable (3rd annunciator lead cable to Generator No. 1; there might be 6 or 9 cables, for example, each with its own number)
G1 = Termination of cable (Generator No. 1)

(6) Cables between low-voltage equipment (such as motor control centers) and minor units of equipment (such as station auxiliaries) have no code letter and numeral to show the termination of the cable run. The cable numbers in these cases are made of only two parts. The first part indicates the start of the cable run, while the second part indicates the type of service rendered by the cable.

Example: Cable Number

Cable ID: CQ5-c12

Breakdown: CQ5 = Start of cable run (480-V load center No. 5)
c = Type of service (Control circuit)
12 = Circuit number

(7) Numbers are assigned to the power and control cables so the power circuit of a given number is controlled by a control circuit having the same number, the differentiation being only in the code letter designation of the circuit duty. As an example, cable “CQ5-c12” would be the control for power circuit “CQ5-q12.”

(8) There are cases where a circuit terminates at several duplicate devices. For instance, an annunciator circuit runs to a junction box and is spliced at this point with branches running to a thermostat in each tank of a transformer bank. In such a case, the cable from the switchboard may have a designation such as S1-u2-T1 and the branch designations are S1-u2.1-T1, S1-u2.2-T1, and S1-u2.3-T1.

(9) Spare conduits are numbered by using a three-part number where possible. In cases where the spare conduits leave a certain switchboard or distribution center and are stubbed at the end of the building, only a two-part number can be used, e.g., CQ01-s1 is a spare conduit leaving motor control center CQ01.

c. Lighting circuits.

(1) Numbering of the circuits and conduits for lighting circuits is similar to the power circuit numbering scheme. Each cable is assigned a three-part number such as SR1-r3-CR4. Full information for these conduits and circuits is given on lighting drawings. Circuits from the lighting cabinets receive numbers corresponding to the switch numbers in the lighting cabinets.

(2) The lighting drawings indicate, between each outlet, the conduit size, number of conductors, and the size of the conductors. The number of conductors is indicated by drawing small lines across the conduit, one line for each conductor. At the side of each outlet, there is a small number indicating the circuit to which the outlet is connected, another number at the side of the outlet indicating the size of the lamp to be installed if not covered elsewhere. Where the conduit leaves the first outlet to run to the lighting cabinet, the circuit numbers of the conductors in the conduit are indicated.

d. Code letter identification.

(1) General. Code letters are broken down into three classes: terminal equipment, modifying terms for terminal equipment, and cable service classification. Code letters and explanations are given in Table 15-1 below.

Table 15-1
Code Letters for Conduit and Cable

Terminal Equipment

• Operator's desk, switchboards, and switchgear

SA - Fishwater Generator Switchboard
SAT - Satellite Digital Processor
S - Generator Switchboard (Add No.)
SB - Battery Switchboard
SC - Main Control Switchboard
SCC - Main Control Console
SG - Graphic Instrument Switchboard
SL - Load Control Switchboard
SO - Station Service Switchboard
SOC - System Operations Controller
SJ - 13.8 *kV* Switchgear (Add No.)
SP - 4160 V (or 2400 V) Switchgear
SQ - 480 V Switchgear (Add No.)
SH - Heating Switchgear
ST - Status Board
SU - Motor Control Center (Add No.)
SR - Lighting Switchgear
SX - Excitation System Equipment (Add No.)
GN - Generator Neutral
OD - Operator's Desk
CC - Carrier Current Equipment
ER - Electrical Equipment Room Cabinets
MUX - Multiplexer
MW - Microwave Terminals
FSC - Fishway Switchboard
DOC - Digital Operations Controller
ROC - Remote Operations Controller
FSP - 4160 V Fishway Switchgear
FCP - 4160 V Fishway Controller
FSQ - 480 V Fishway Switchgear
FSU - Fishway Unit Switchgear
TF - Telephone Frame

• Load centers

CP - 4160 V (or 2400 V)
CQ - 480 V
CR - 120/240 V (120/208 V)
CD - 48 V DC
CE - 125 V DC
CF - 250 V DC
CA - Emergency Lighting
CH - Preferred AC
CY - (CO_2) Cabinet
DQ - 480 V (Dam)
FCP - 4160 V (or 2400 V) Fishway
FCQ - 480 V (Fishway)
PQ - 480 V (Project)

• Apparatus

A - Actuator (Governor)
B - Battery
G - Generator
GF - Fishwater Generator
X - Breaker (Add Voltage Letter)
T - Transformer (power)
Z - Disconnecting Switch (Add Voltage Letter)
CT - Current Transformer
V - Voltage Transformer
EG - Engine Generator
MG - Motor Generator
MC - Motor Control Cabinet
M - Motor
PT - Potential Transformer (Separate Apparatus modified by voltage as PTW)
K - Crane
FT - Fishway Transformer

• Miscellaneous terminal equipment, boxes, or structures. Some items in this list are used for cable and conduit terminals, but a majority are used only as modifying suffixes for devices on schematic diagrams:

AA - Governor Air Compressor
AH - Air Horn
AN - Annunciator
AQ - Governor Oil Pump
AR - Annunciator Reset
AS - Ammeter Switch
BC - Battery Charger
BG - Break Glass Station
BK - Brakes
BU - Bubbler System
BV - Bypass Valve or Butterfly Valve
CAC - Central Air Conditioner
CJB - Junction Box, Master Control Circuits (Modify by Unit No.)
CM - Channel Manometer
CPD - Capacitance Potential Device
CTC - Control Terminal Cabinet
DP - Drainage Pump
DS - Deck Station
DT - Differential Transmitter (Transducer)
DWP - Domestic Water Pump
EA - Sewage Aerator
EC - Effluent Comminutor
EF - Exhaust Fan
EH - Electric Heater
EHQ - Electric Oil Heater
EL - Elevator
EP - Sewage (Effluent) Pump
ETM - Elapsed Time Meter
EV - Electrically Operated Valve
FM - Flow Meter
FP - Fire Pump
FS - Float Switch (Device 71 preferred)
FTC - Fishway Terminal Cabinet
FW - Float Well
FWG - Forebay Water Level Gage
GH - Generator Heater
GI - Ground Insert
GP - Grease Pump
GW - Generator Cooling Water (Pump or Valve)
HC - Head Cover Sump Pump
HD - Air Conditioning Damper
HF - Air Conditioning Air Filtration Equipment

(Continued)

Table 15-1. (Concluded)

HH - Air Conditioning System Humidifier
HP - High Pressure Thrust Bearing Oil Pump
HQ - Conditioning System Oil Pump
HR - Air Conditioning System Refrigeration Pump
HV - Air Conditioning System, Master Devices
HW - Air Conditioning System Water Pump
HY - Hypochlorinator
IG - Intake Gate
IM - Intake Manometer
IS - Intruder Detector System
IQ - Intake Gate Oil Pump
IV - Inverter
JB - Junction Box
LC - Load Control Cabinet
LT - Outside Lighting (480 V)
LTH - High Bay Lighting
LTU - Line Tuning Unit
MO - Load Control Master
MOD - Motor Operated Disconnect
OR - Operations Recorder
OS - Load Control Station Operation Selector
PA - Station (Plant) Air Compressor
PB - Pull Box or Pushbutton
PC - Program Controller
PG - Penstock Gate
PH - Powerhouse (Add No.)
PR - Project Building
PS - Potential Selector or Pressure Switch (Device 63 preferred for pressure switch)
PT - Pressure Tank
PV - Penstock Valve
QPD - Oil Transfer Pump (Dirty)
QPL - Oil Transfer Pump (Lube)
QPT - Oil Transfer Pump (Transil)
RC - Code Call Relay Box
RF - Recirculating Fan
RW - Raw Water Pump
SD - Servo or Shaft Oil Catcher Drain Pump
SF - Supply Fan
SN - Stop Nut
SO - Load Control System Selector
TA - Transformer Cooling Equipment Air System
TB - Telephone Box or Test Block
TBA - Turbine Bearing Oil Pump - AC
TBD - Turbine Bearing Oil Pump - DC
TC - Terminal Cabinet
TD - Transformer Deluge
TE - Thermostat (Heating & Ventilation Equipment Drawings)
TH - Preferred AC Transformer
TM - Tailrace Manometer
TP - Turbine Pit
TQ - Transformer Cooling Equipment Oil Pump
TS - Test Station
TWG - Tailwater Level Gage
UAC - Unit Air Conditioner
ULC - Unit Load Control Selector
US - Unit Selector
UV - Unloader Valve
UW - Unwatering Pump
VQ - Valve Oil Pump
XA - Circuit Breaker Air Compressor
XF - Circuit Breaker Cooling Fan
VS - Voltmeter Switch
WG - Water Gate (Sluice, Weir, etc.)
WH - Water Heater (Hot Water Tank or Boiler)
WP - Gate Wash Pump - Deck Wash Pump
WV - Water Valve

Modifying terms for terminal equipment

• As an aid to further identification of voltage class and location of the equipment, the following letters are applied to separately mounted breakers, disconnecting switches, current transformers, and voltage transformers:

U - 500 *kV*
M - 230 *kV*
W - 115 *kV*
J - 13.8 *kV* or 7.2 *kV*
P - 4160 V (or 2400 V)
Q - 480 V
R - 120/240 V (120/208 V)
F - 250 V DC
E - 125 V DC
D - 48 V DC
H - 120 V Preferred AC

• Other modifying terms

O - (as GO, TO) - Station Service
N - (as GN1, TN1) - Neutral
Y - (as CY for CO_2 Cabinet) - CO_2

Service classification

a - Current Transformer - Shunt Leads
c - Control Circuits, (Circuit Breaker Control Circuits, Excitation System Control Circuits, and Governor Control Circuits)
d - 0 - 48 V DC
e - Power Circuit, 125 V DC
f - Power Circuit, 250 V DC
h - 120V Preferred AC
j - Power Circuit, 13.8 *kV* AC
m - Power Circuit, 230 *kV* AC
p - Power Circuit, 4160 V or 2400 V AC
q - Power Circuit 480 V AC
r - Power Circuit (Lighting) 120/240 V or 120/208 V AC
s - Spare Conduit
tr - Radio Circuits
t - Telephone Circuits, Intercommunication Circuits
ts - Sound Power Circuit
u - Alarm Circuits; Annunciator Circuits; Water Flow Level; Pressure; and Temperature Indicating and Recording Circuits; Telemetry, Analog, Operations Recorder, etc.
uc - Code Call Circuits
v - Voltage (Potential) Transformer Secondaries and DC Voltage Leads
ut - Carrier or Pilot Wire Circuit
x - Excitation Circuits

e. Code identification notes.

(1) The list of letters in paragraph 15-4*d*(1) is used for separately mounted apparatus only. Instrument transformers and disconnecting switches are given individual designations only if they are mounted by themselves, as in an outdoor structure or in a similar indoor arrangement.

(2) Instrument transformers and disconnecting switches mounted on a circuit breaker or circuit breaker structure have the cable and conduit designations of the breaker. For example, bushing-type current transformers and potential devices mounted on oil circuit breaker XJ3 have cable and conduit designations such as "S3-a1-XJ3" and "S3-v1-XJ3"

(3) Cable terminal designations are used to designate major assemblies such as a switchgear assembly and not an individual breaker within the switchgear. Individual breaker designation is desirable, but including it in the terminal designation (first term of cable code) would complicate the system impairing its usefulness. Thus, instrument transformers, breakers, and disconnecting switches mounted in a switchgear or switchboard take the terminal designation of the switchgear or switchboard. For example, a breaker mounted in a 480-V switchboard has a cable and conduit designation of "SQ" for the first term and even though the breaker may have a number, this number is disregarded in the first term of the cable code. Where there are only a few breakers, the lack of a more positive identification is not objectionable.

(4) When a switchboard has a large number of breakers, considerable time may be consumed in locating the cable. To overcome this objection, the second term of the cable code is numbered to correspond with the breaker number. For example, CQ2-q8 and CQ2-q25 are 480-V power circuits connected to breaker No. 8 and No. 25, respectively, in 480-V cabinet No. 2. No difficulty is encountered because the number in the second term serves to differentiate one cable from another and doesn't indicate the total number of cables from a point.

(5) The order of terminal designation follows the order given in the code. For example, a cable between a lighting switchboard and a lighting cabinet is designated as "SR2-r4-CR5." The switchboard table precedes the load center table, the switchboard designation being the first term and the load center the last term. Other examples would be SJ-j2-G1 and CP-p1-K2. This order of designation is maintained for items of the same table; e.g., SC-a1-SP or A2-c1-G2.

(6) Because of the complicated code, the designation's primary application is in the powerhouse. The same designation may be used with a prefix to signify location at a different feature of the project. For example, DCR can represent a lighting cabinet in the dam.

(7) Similarly, FCQ represents a fish facility 480-V control center. This system is maintained at the powerhouse for terminal equipment, cables, and conduits servicing the fishway next to the powerhouse and also is maintained partially at the fishway. However, on portions of the fishway including collection channels, diffusion chambers, and the various gates, it is desirable to use designations employed in the structural and mechanical design and having name familiarity. Designations and locations of these elements of fish facilities are project-specific.

(8) Cable running from one part of the project to another should be clearly identified. For instance, the 4160-V cables originating at the powerhouse and used to supply power for the fishway, dam, and lock may have a designation SP - p1 to the first point of connection, SP - p1.1 between the first and second points of connection, and SP - p1.2, and so on, for the subsequent points.

(9) Powerhouse drawings showing the cable running to the fishway should indicate the cable number and give reference to the fishway drawing in which the other terminal of the cable is shown. Similarly, the fishway drawings should indicate the cable numbers for the cable in both directions and references given to both powerhouse and dam drawings.

(10) Wiring diagrams for a large switchboard or switchgear assembly are on several drawings, so considerable time is consumed in locating the proper drawing and the proper panel. To avoid this difficulty, each switchboard has its front panels numbered in order from left to right. The panel designation is the switchboard designation followed by the panel number, and the cable number then designates the panel at which it terminates. For example, on Generator Switchboard No. 1, the third panel from the left would be designated "S13" and a cable running from this panel has a designation such as, "S13-c1-TO."

(11) In duplex switchboards, a rear panel is designated by the letter "R" followed by a number corresponding to its front panel. For example, on Generator Switchboard No. 1, the third rear panel from the right

(facing the front of the rear panels) is designated "S1R3" and a cable running from this panel has a designation such as "S1R3-c1-TO."

(12) Some vertical sections of a motor control center assembly may include two or more lighting panels, in one instance with the same voltage classification (e.g., CR-r and CA-r). The lighting panel designation is used in lieu of the vertical section number in these instances. A motor control center could include lighting panels of the following designations:

SU1 - - - CR11, CE11, CF11, CA11, CB11

SU2 - - - CR21, CE21, CF21, CA21, CB21

SU3 - - - CR31, CE31, CF31 CA31, CB31

SU4 - - - CR41, etc.

f. Lighting circuits. With lighting circuits, it is desirable to deviate from the general plan of providing a relationship between the conduit and its contained circuits. Branch circuits from lighting cabinets are numbered to comply with the power circuit guide. The numbering of branch conduits from lighting cabinets complies with the guide, except the conduit number bears no relationship to the numbers of the circuits running through it. The conduit number is initially determined by sequence numbering in a clockwise direction from the upper right-hand corner when facing the lighting cabinet and is not affected by circuits and conduits feeding the lighting cabinet. Where more than one row of knockouts is involved, the sequence of numbering is from front to back and clockwise.

Chapter 16
Procedure for Powerhouse Design

16-1. Design Initiation

Design for a powerhouse is initiated during engineering and design activities supporting preconstruction planning studies. The planning studies accompany reports to Congress seeking initial authorization for a project. The accompanying studies are either reconnaissance reports or feasibility studies with an engineering appendix. If favorable congressional action is received as a result of initial authorization activities, further engineering and design activities are conducted including preparation of a General Design Memorandum (GDM). The GDM is incorporated into documentation submitted to higher authority seeking a construction start. ER 1105-2-100 provides further information on the contents of these reports. Chapter 17 describes requirements for the GDM. At each stage of the process, powerhouse design is further refined.

16-2. Design Process

After a project has been authorized and funds appropriated or allotted for design of the power plant, criteria outlined in Guide Specification CE 4000, Appendix A, should be followed regardless of the organization performing the design. The criteria outline a process of preparation of Feature Design Memorandums covering the design features of the power plant, preparation of plans and specifications, and other engineering activities involved in implementing design, construction, and commissioning of the power plant. The field operating activity (FOA) can utilize either the Hydroelectric Design Center (HDC) or an architect engineer (A-E) to provide the engineering and design services for developing powerhouse design, preparing plans and specifications, reviewing vendor drawings, assisting in preparation of operation and maintenance manuals, and providing record drawing documentation.

Chapter 17
General Design Memorandum

17-1. Requirements

Format and content requirements for the General Design Memorandum (GDM) are described in ER 1105-2-100. The general features of the selected power plant design are presented and analyzed by means of sketches, diagrams, and cost comparisons. Sketches, diagrams, and cost comparisons are used to explain plan formulation and the plan selection process. The electrical drawings required for the memorandum, in addition to equipment locations shown on general floor plans, consist chiefly of one-line diagrams. Approximately six to eight drawings are sufficient to show main unit and switchyard connections, the station service scheme, the control and protective relaying schemes, the communications system, and a lighting feeder scheme. Major equipment information, obtained from vendors, should be included in the appendixes. If the report is approved, it becomes a guide for subsequent detailed engineering developed in Feature Design Memorandums and design drawings (covered in Chapter 18).

Chapter 18
Feature Design Memorandums and Drawings

18-1. Design Memorandum Topics and Coverage

Following approval of the General Design Memorandum, engineering, design, and drawing preparation for the power plant proceed using Feature Design Memorandums (FDM) and accompanying drawings. A completion schedule for each of the planned memorandums and a sequence of submission is developed for the concurrence and approval of the field operating activity (FOA) and higher authority early in the process. Design memorandum sequence and submission dates should be coordinated with the power plant construction schedule and equipment procurement schedules. Timing and sequence of submission are scheduled to maximize review time and allow effective use of engineering resources of the review agency.

18-2. Feature Design Memorandums

FDMs are normally prepared for electrical equipment and systems purchased by the Government. They are also prepared for electrical systems having a significant content of Government-furnished equipment. The plans and specifications required for purchased equipment are based on the design parameters and information contained in the FDM. Typical equipment and systems requiring FDMs include generators, step-up and station service transformers, generator bus and breakers, station service switchgear, power plant energy management systems (SCADA), 480-V station service and distribution systems, station battery systems, and station lighting and distribution systems.

18-3. Engineering Documentation

The engineering documentation in FDMs should include the methods, formulas, detailed computations, and results (if results are obtained from engineering software programs) used to determine equipment and system ratings and technical design parameters. Design alternatives investigated during the equipment or system selection process should be discussed together with the rationale for choosing the selected alternative. FDMs should contain sufficient detail not only to facilitate the checking and review process, but to allow preparation of plans and specifications accurately conveying the design intent.

18-4. Design Drawings

Design drawings accompanying an FDM will conform in general to the requirements mentioned in the following paragraphs.

a. Generators. No design drawings are necessary for generators, unless needed to depict unusual generator lead arrangements, or illustrate connections to and location of excitation equipment.

b. Transformers. Design drawings for either generator step-up or station service transformers are not required with FDM submission.

c. High-voltage system. Drawings locating the switchyard with respect to the powerhouse, depicting cable tunnel or cable duct locations, and providing details on bay widths, types of structures, and phase-to-phase and phase-to-ground clearances should be furnished. A plan of the switchyard, including line bay and transformer bay sections and a switchyard one-line diagram, will adequately convey the design intent.

d. Generator-voltage system. A plan of the arrangement of the generator bus and breaker system, together with locating and limiting dimensions, equipment ratings, generator surge protection equipment, and excitation system power potential system taps, should be provided with the FDM. In addition, a plant one-line diagram should be provided.

e. Station service systems. Drawings with arrangements, locations, limiting dimensions and one-line diagrams for medium-voltage switchgear, low-voltage switchgear, and low-voltage motor control centers of the station service system should be included with the FDM.

f. Control system. Drawings included with the control system FDM should define the design of the plant energy management (SCADA) system, the plant control and relay scheme, the control and protective relay switchboards, and associated equipment. The plans should provide sufficient information regarding control and protective relay functions to convey the intended operations of the plant's control and protective relaying systems. Typically, unit one-line diagrams, unit and plant control and protective relaying schematics, station service control and protective relaying schematics, and block diagrams of the plant's energy management system adequately provide this information. In addition, a control room layout, and a layout with control equipment locations, together with locating and limiting (if necessary) dimensions, is provided.

g. Communications systems. A drawing of the extent and composition of leased commercial telephone facilities, the code call system, and dedicated communications systems for utility communications, telemetry, and plant energy management systems (SCADA) should be provided. Drawings with locations of the commercial telephone main distribution frame, code call stations, and dedicated communication system components of either the power line carrier, microwave system, or the fiber-optic system should be provided.

h. Direct current system. In addition to the one-line and schematics described in paragraph 18-4*f*, a preliminary layout should be provided of the DC system equipment. The drawing should include the rating of battery chargers, inverters, and batteries; any limiting dimensions of equipment; and the arrangement of the battery cells.

i. Lighting and receptacle systems. Drawings of the plant normal and emergency lighting systems should be provided. Information regarding connected lighting system loads, intended feeder sizes, and location of lighting distribution panels and transformers should be included. In addition, information on intended lighting intensities throughout the plant and proposed types of luminaires should be provided.

j. Grounding systems. A plan of the power plant ground mat, including taps to major equipment, should be provided. A similar plan should be provided if a separate switchyard ground mat is included in the project development.

k. Conduit and cable tray systems. Design layouts with locations and preferred methods of routing major conduit runs (including number and size of conduit) should be provided. Similar layouts should be provided for the plant's cable tray systems. These preliminary layouts form the basis for detailed drawings of these systems prepared for the powerhouse construction contract.

l. Wire and cable. Design drawings are not prepared for this phase of the work.

Chapter 19
Construction Specifications and Drawings

19-1. Specifications

a. Types of contracts. Construction specifications and drawings for hydroelectric power plant work are used for two different classes of contracts: supply contracts for the purchase of built-to-order equipment from manufacturers; and construction contracts for the building of the powerhouse, switchyard, and related structures. When construction begins before engineering and design of all features are completed, second- and third-stage construction contracts are used to cover the superstructure and/or wiring and installation of machinery and equipment.

b. Selection of contract type. The choice of whether to include electrical equipment procurement within the powerhouse construction scope of responsibility, to directly purchase the required equipment for installation by the contractor (installation only), or to procure design, fabrication, and installation of equipment ("turn-key") is dependent upon a number of factors. These factors include equipment procurement lead times, the complexity of the fabricated equipment, and the need for specialized installation skills. Generally, supply contracts are used to procure equipment with long lead times, equipment with a high degree of complexity, or equipment requiring specialized installation skills and techniques. Typical equipment procured with supply contracts includes generators (turn-key procurement), SCADA systems, high-voltage bus and breakers, generation step-up transformers, and generator- and high-voltage power circuit breakers. Low-voltage switchgear, motor control centers, lighting panels, and cable tray systems are typical of equipment included in a construction scope of supply.

c. Specification preparation. General criteria and policies to be observed in preparing specifications are found in Appendix A of Guide Specification CE-4000. Specifications and plans should be carefully coordinated, and various sections in a given specification (sometimes prepared by different writers) checked to ensure consistency, eliminate conflicts, clearly define limits of payment items, and avoid overlapping payments for any item. Specifications are prepared to accommodate three classes of users of the specifications: the construction and/or manufacturing contractor, the resident engineer, and the field or shop inspector. Specifications for Corps of Engineers civil works projects differ from private sector practices because the specifications and plans must be self-explanatory without amplification about details of the construction or equipment fabrication. Typically, private sector specifications depend on interpretations of the engineering organization designing the project. Private sector specifications are unsuited to the Corps of Engineers' competitive open bidding methods of awarding contracts and performing the work.

19-2. Construction Drawings

a. General. Construction drawings should be complete and based on commercially available equipment and industry-recognized construction and installation techniques. Details of equipment design and installation, wiring, and conduit should be complete to minimize the need for field revision. Discussions in the following paragraphs indicate the type and scope of information that should be included on construction drawings for the various phases of work covered by this chapter.

b. Generators.

(1) Selected or modified drawings from the general arrangement drawings of the powerhouse are generally used to accompany the specifications for purchase of generators. Drawings prepared to accompany guide specifications should indicate various mechanical and electrical interfaces including main leads, piping terminations (e.g., lube oil, cooling water, CO_2, brake air), neutral equipment locations, and excitation system equipment locations.

(2) A plant or main unit one-line diagram should also be included in the procurement drawing set. Equipment centerline should be dimensioned from structure lines. Powerhouse crane hook coverage should be shown on the appropriate procurement drawing set. Other governing or limiting dimensions should be established. Locations and dimensions of openings, sleeves, and interfering equipment should be shown where possible. In cases where dimensions cannot be determined until later, the dimension lines should be drawn in and indication made that the dimension will be added at a later date. Generator procurement drawings may be included in the construction contract set to show the extent of generator erection performed by the generator supplier.

c. Transformers.

(1) Suitable drawings showing the location and general arrangement of the transformers and connecting bus structures and limits of work under the contract

should be included with the transformer procurement specifications.

(2) The drawings should include all features not adequately covered in the specifications affecting the design of the transformers or powerhouse, such as limiting transformer dimensions, rails and other provisions for lifting and moving the transformers, locations of terminal cabinets, surge arresters, chilling sumps and walls between transformers, bushing enclosures for connection to metal-enclosed bus, and location of heat exchangers. Other details include size of oil pipes for Class FOW transformers where the heat exchangers will be installed remotely from the transformers, types and sizes of bushing terminal connectors, and provisions for grounding the neutrals of the high-voltage windings and the transformer tanks.

d. High-voltage system. Construction drawings for this system should show all necessary layouts and details for installation of equipment from the high-voltage bushings of the transformers to the outgoing transmission line interface in the switchyard. These plans should include drawings of the high-voltage leads with details of termination points; switchyard equipment arrangement drawings, including plans, sections, elevations, and details; structure loading diagrams; conduit and grounding plans; and details of lighting and power panels and other miscellaneous equipment. A one-line diagram of the high-voltage system should be prepared, together with control schematics of controlled equipment. Manufacturers' shop drawings are used to a great extent in the actual installation of equipment.

e. Generator-voltage system. Drawings for the generator-voltage system should show sufficient details for purchase of the generator main and neutral leads and associated equipment, and the generator switchgear if included in the supply scope. The drawings should show the general layout, details of arrangement and ratings of equipment, limiting dimensions, termination methods, and a one-line diagram showing items of equipment. If the supply scope includes generator switchgear, control schematics of the controlled equipment should be provided. These drawings are also included with the drawings for the construction contract to show the extent of the installation work. Manufacturers' detail drawings are used for installation of this equipment.

f. Station service systems.

(1) General. Construction drawings for the station service system should consist of the station service one-line diagram and drawings used for purchase of the switchgear and motor control centers, if supply of this equipment is not included in the construction scope of supply.

(2) Station service switchgear.

(a) The station service switchgear drawings should show all information necessary for design of the switchgear and, insofar as possible, the information needed for installation.

(b) The switchgear drawings should indicate the frame size and ampere rating of each breaker, as well as the nameplate designation of each circuit. Wire sizes of outgoing feeders should be provided for correct sizing of circuit breaker lugs. The number and rating of current and potential transformers should be indicated. The preferred layout of indicating and control equipment should be shown.

(c) A one-line diagram should be prepared of the switchgear line-up. Centerline dimensions and preferred routing of any bus included in the switchgear scope of supply should be provided.

(d) Drawings showing the switchgear installation should be prepared with sufficient arrangement flexibility to accommodate variations in dimensions among equipment suppliers. Drawings prepared for the purchase of the switchgear are also included in the contract construction drawings to indicate the scope and complexity of installation and connection. Manufacturers' shop drawings are used for installation of the switchgear.

(3) Motor control centers.

(a) Drawings for motor control centers are similar in scope to the drawings of the switchgear. Motor control centers consist of free-standing cubicles containing combinations of standardized factory subassemblies. The standardized units described in Chapter 7 are preferred.

(b) Outside dimensions of embedded cabinets and locations of conduits for supply and branch circuits should be shown. Motor control center elevations indicating preferred location of starters, control switches, and nameplates should be shown. A one-line diagram with the relative positions of equipment enclosed within the control center, direction of bus runs, the location of bus lugs, and the ratings of all equipment should be provided.

(c) The drawings should contain tabulations of the circuit number, the nameplate designation of the circuit, the expected load, the breaker frame size, the starter size, and the number and size of conductors.

(4) Lighting and power panelboards.

(a) The purchase and installation of lighting and power panels are included in the powerhouse construction contract. Drawings are prepared showing the size of the embedded cabinets, the size of the front covers, bus diagrams, and any pertinent details such as space allocation and wiring diagrams for throw-over switches or remote control switches located in the panels. Tabulations of main bus current ratings, main breaker ratings, location and sizes of main and neutral lugs, and the number and ratings of branch-circuit breakers should be included on the drawings.

(b) Lighting plan circuit designations should be provided on the panel bus diagrams. Panel layouts should provide space for spare and future circuit breakers.

(c) Doors, locks, and details of door openings should be shown. Front covers should overlap the embedded cabinet approximately 1 in. all around. All contactors should be completely separated by barriers from other equipment and from wire gutters.

(d) Buses should also be completely enclosed except at the ends of runs. The necessity for the removable cover over the bus lugs should be considered in locating equipment within the cabinet.

g. Control system. Drawings issued for purchase of switchboards, control panels, and the operator's control console (if required), comprising the plant control system, should include plant and unit one-line diagrams, plant and unit control and protective relay schematics, station service control and protective relay schematics, and associated equipment. Other drawings that should be in the drawing package include switchboard and control console arrangements showing preferred locations of relays, instruments, and control switches. Preparation of wiring diagrams for this equipment should be included in the manufacturer's scope of supply, together with the preparation of terminal connection diagrams to which external plant interconnection details can be added during the shop drawing review process. If a plant energy management system (SCADA) is incorporated in the control system procurement, block diagrams of the system should be incorporated with the procurement drawing set. Control system drawings are also incorporated in the construction drawing set for information as to the extent of the installation work. Actual installation of the control system should be performed in accordance with the manufacturer's approved drawings. Included in the construction set should be drawings providing locating dimensions for control system equipment.

h. Annunciation system. Generally, annunciators are included in the scope of supply for the control switchboards. A drawing of the incoming trouble and alarm points to the annunciators, together with preferred window arrangements and window legends, should be provided. Incoming trouble, alarm, and event points to the plant sequence-of-event recorder (SER), together with a preferred format for printout of recorded events, should be provided on the drawings.

i. Communications system. Drawings that define the scope of facilities that will permit the installation of communication termination equipment should be included in the construction drawing set. The construction contractor will provide the facilities. The communication termination equipment will be furnished and installed by others (see Chapter 10). In addition, a drawing with locations of the plant's code call system should be prepared.

j. Direct current system. The drawing for the purchase of the battery switchboard is similar in scope to those for the equipment discussed in paragraph 19-2*g*. The battery switchboard is generally purchased with the control switchboard. The battery switchboard drawing is included with the construction contract drawings to depict the extent of the work and provide explanatory material.

k. Lighting and receptacle systems.

(1) Lighting drawings on the lighting plan for an area should show all fixture, switch, and receptacle outlets, and all conduits in the walls and ceiling.

(2) Conduits in the ceiling and walls of an area are shown on a floor plan of that area. Conduit in the floor slab for the same area, even though used to feed outlets in the area, should be shown on another plan as in the ceiling for the area below.

(3) Building and room outlines, beams, and openings, should be shown. Rooms should be identified. Normally, it is not necessary to show equipment on lighting drawings. Sections and details should be shown where necessary for clarification. Wiring diagrams and equipment should be detailed in accordance with the drawing legend. All outlets, junction boxes, and conduit

terminations should be located by dimensions and, if necessary, by elevations.

(4) The conduit system should be detailed completely and all sizes and materials noted. Embedded conduit for branch circuits should be limited to ¾- and 1-in. sizes if possible. Conduits serving ceiling fixtures in areas with suspended ceilings should be stubbed out of the concrete. The conduit will be extended to fixture outlet boxes before placing the ceiling suspension system.

(5) Boxes, extension rings, and covers should be suited to the finish of the space in which they are used with appropriate notations or details made on the drawings to ensure the use of the proper materials and fittings. Wall outlet boxes should be sheet metal boxes with suitable extension rings when located above the generator room floor. On turbine room walls, boxes should be cast boxes meeting the requirements of UL 514A.

(6) Complete details should be given for lighting fixture mountings, wiring devices, and device plates. Circuits should be designated by lighting panel number and circuit number and balanced across the lighting panel buses and transformer. The number and sizes of wires in each conduit are indicated by standard hash marks and notes. The system should be color-coded as noted on the typical drawing.

(7) To avoid confusion, local switches and their controlled fixtures should have an individual letter designation to indicate their relation. Fixture, switch, and receptacle types should be designated on the drawings and referred to a schedule giving the fixture type by reference to a catalog product or to a detail drawing. The schedule should also show all mounting fittings.

l. Grounding systems. Grounding system drawings should include all plans, information, and details necessary for the installation of the power plant ground mat, the main powerhouse grounding network, and taps and connections to equipment. The taps from the main ground network to equipment may be shown conveniently on the power and control conduit plans. Details should include test stations if used, water seals, exposed ground bus supports, and typical connections to the frame or housing of plant equipment and metal structures.

m. Conduit and cable tray systems.

(1) Conduit plans for station service power and for all control circuits, including the communication system, should show the conduits in the floor and walls of the designated area. Obstructions, structural features, and locations of equipment influencing conduit location should be shown on the drawings.

(2) Conduits should be in accordance with the legend. Each conduit should be labeled with the size and conduit number shown in the conduit and cable schedule. Conduit termination locations should be dimensioned to building control lines wherever possible.

(3) All outlet boxes and cabinets should be shown on the drawings with size, location, and, if applicable, designation numbers given. Any required boxes should be located and detailed.

(4) Where a number of conduits stub out of a wall or floor within a small area, a structural steel terminal plate should be detailed for use in holding the conduits rigidly in place during concrete placement operations. If conduit locations are not known when the drawings are prepared, indication should be made that dimensions will be furnished at a later date.

(5) Sufficient elevations and details of conduits entering junction boxes, pull boxes, or cabinets should be provided showing the complexity of the work and the quality and size of allowable electrical construction materials. Where stubs are left in concrete walls or ceilings for exposed runs to equipment, the conduit should be stubbed flush with a coupling and closed with a pipe plug.

(6) One or two spare conduits should be run from each motor control center or lighting panel wall location to 6 in. below the ceiling of the room in which the installation is located and terminated in a flush coupling. One or more spare conduits should be similarly terminated in the room below the installation.

(7) Pull boxes, embedded power cabinets, and junction boxes should be completely detailed to show size, material, flange width, front covers, and conduit drilling. For cast iron boxes, a standard catalog product with drilled and tapped conduit entrances is specified.

(8) Drawings should show the arrangement and location of the complete tray system. Details of tray hangers, supports and splices, and supporting blocks for cables entering or leaving the trays, should be shown on the drawings. The trays should be suitably identified for listing in cable schedule references. Construction details of all fabricated components should be provided on the drawing. Component totals should be included on a bill of materials.

n. Wire and cable. The cable and conduit schedule should be prepared as outlined in Chapter 15. It is convenient to list the multiconductor control cables separately from power cables. Computer-generated spreadsheets are generally used for listing all power plant power, control, and communications cables. The locations of wire and cable in trays should be shown on tray diagrams. These diagrams will expedite construction and provide “as constructed” engineering documentation useful for plant maintenance.

Chapter 20
Analysis of Design

20-1. Permanent Record

The "Analysis of Design" memorandum should be a permanent record for future reference. It should consolidate into one document engineering information and computations from previously approved design memorandums pertinent to the executed plans and specifications.

20-2. Up-To-Date Values

Original computations based on assumed values for machine or equipment characteristics are revised to reflect up-to-date values based either on the manufacturers' design calculations or on field or factory test measurements.

20-3. Expansion

If provisions are made in the powerhouse or switchyard design for future addition of units, transmission lines, or auxiliary equipment, the Analysis of Design memorandum should detail the provisions for the expansion.

Appendix A
References

A-1. Required Publications

TM 5-810-1
Mechanical Design, HVAC

ER 1105-2-100
Guidance for Conducting Civil Works Planning Studies

ER 1110-2-103
Strong Motion Instrument for Recording Earthquake Motions on Dams

EM 1110-2-3001
Planning and Design of Hydroelectric Power Plant Structures

EM 1110-2-4205
Hydroelectric Power Plant Mechanical Design

CE 4000
Civil Works Guide Specification for Lump Sum Contract for Engineering Services for Design of Hydroelectric Power Plant

CW-13331
Civil Works Guide Specification for Supervisory Control and Data Acquisition Equipment

CW-16120
Civil Works Guide Specification for Insulated Wire and Cable

CW-16211
Civil Works Guide Specification for Rewind of Hydraulic-Turbine-Driven Alternating Current Generators

CW-16252
Civil Works Guide Specification for Governors for Hydraulic Turbines and Pump Turbines

CW-16320
Civil Works Guide Specification for Power Transformers

AIEE Transactions on Power Apparatus and Systems, 1953 (Oct)
Characteristics of Split-Phase Currents as a Source of Generator Protection, Paper 53-314.

ANSI C2-1993
National Electrical Safety Code

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

ANSI C37.16-1980
American National Standard Preferred Ratings, Related Requirements, and Application Recommendations for Low-Voltage Power Circuit Breakers and AC Power Circuit Protectors

ANSI C37.90.1-1989
IEEE Standard Surge Withstand Capability (SWC) Test for Protective Relays and Relay Systems (ANSI)

ANSI C80.1-1983
Rigid Steel Conduit-Zinc Coated

ANSI C84.1-1989
American National Standard Voltage Ratings for Electric Power Systems and Equipment (60 Hz)

ANSI/IEEE 242-1986
IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems

ANSI/ISA S18.1-1981
Annunciator Sequence and Specifications

EPRI EL-5036
Power Plant Electrical Reference Series, Vol. 2, “Power Transformers”

EPRI EL-5036
Power Plant Electrical Reference Series, Vol. 4, “Wire and Cable”

EPRI EL-5036
Power Plant Electrical Reference Series, Vol. 5, “Grounding and Lightning Protection”

EPRI EL-5036
Power Plant Electrical Reference Series, Vol. 9, “DC Distribution”

EPRI EL-5036
Power Plant Electrical Reference Series, Vol. 10, “Electrical and Instrumentation”

EPRI EL-5036
Power Plant Electrical Reference Series, Vol. 13, “Communications”

EPRI TR-101710, 1993
EPRI Lighting Fundamentals Handbook

IEEE Transactions on Power Apparatus and Systems, 1983
IEEE Transactions on Power Apparatus and Systems, 1983, Vol PAS-102, No. 9 (September).

IEEE Transactions on Power Apparatus and Systems, 1983
IEEE Transactions on Power Apparatus and Systems, 1983, Vol PAS-102, No. 10 (October).

IEEE 43-1974
IEEE Recommended Practice for Testing Insulation Resistance of Rotating Machinery (ANSI)

IEEE 80-1986
IEEE Guide for Safety in AC Substation Grounding (ANSI)

IEEE 81-1983
IEEE Guide for Measuring Earth Resistivity, Ground Impedance, and Earth Surface Potentials of a Ground System

IEEE 115-1983
IEEE Test Procedures for Synchronous Machines (ANSI)

IEEE 142-1991
IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems (ANSI)

IEEE 399-1990
IEEE Recommended Practice for Power Systems Analysis

IEEE 422-1986
IEEE Guide for Design and Installation of Cable Systems in Power Generating Stations (ANSI)

IEEE 450-1987
IEEE Recommended Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations (ANSI)

IEEE 484-1987
IEEE Recommended Practice for Installation Design and Installation of Large Lead Storage Batteries for Generating Stations and Substations (ANSI)

IEEE 485-1983
IEEE Recommended Practice for Sizing of Large Lead Storage Batteries for Generating Stations and Substations (ANSI)

IEEE 605-1987
IEEE Guide for Design of Substation Rigid-Bus Structures (ANSI)

IEEE 946-1992
IEEE Recommended Practice for the Design of DC Auxiliary Power Systems for Generating Stations

IEEE 979-1984 (Reaffirmed 1988)
IEEE Guide for Substation Fire Protection (ANSI)

IEEE 980-1987
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Appendix B
Power Transformer Studies and Calculations

B-1. Recommended Studies

a. The following studies should be performed during the preliminary design phase for generator step-up power transformers:

(1) Transformer *kVA* Rating Study.

(2) Transformer Cooling Study.

(3) Basic Impulse Insulation Level (BIL) / Surge Arrester Coordination Study.

(4) Transformer Bushings Rating Study.

(5) Transformer Efficiency Study.

(6) Transformer Loss Evaluation Study.

(7) System Fault Study for Transformer Impedance Determination.

b. This appendix outlines samples of these studies and calculations as listed above. Sample studies for items (a) and (b) are not included due to their lesser degree of complexity and site-specific nature (a discussion concerning transformer ratings and cooling considerations is included in Chapter 4). A system fault study should be performed prior to determining transformer impedances. A sample system fault study is not included in this appendix due to its expanded scope and site-specific nature.

B-2. Data Used for Sample Studies

a. The sample studies shall be based upon the following assumed data:

(1) Transmission line data:

- 230 $kV_{L\text{-}L}$
- 750 *kV* BIL rating

(2) Generator data:

- 69,000 *kVA*
- 110 *kV* winding BIL

(3) Transformer data:

- 46,000 *kVA*
- 13.2 *kV*/115 *kV*
- two-winding
- 1ϕ
- FOA type cooling

B-3. Sample Study B1, BIL / Surge Arrester Coordination

a. Objective.

The objective of this study is to determine the following:

(1) Transformer high-voltage basic impulse insulation levels (BIL's).

(2) Transformer impulse curves.

(3) Surge arrester type and sizing.

(4) Surge arrester impulse curves.

(5) Transformer high-voltage BIL / surge arrester coordination.

b. References.

The following references were used in the performance of this study. Complete citations can be found in Appendix A of this document, "References."

(1) ANSI C62.1-1984.

(2) ANSI C62.2-1987.

(3) ANSI C62.11-1987.

(4) ANSI/IEEE C57.12.00-1987.

(5) ANSI/IEEE C57.12.14-1982.

(6) ANSI/IEEE C57.12.90-1987.

(7) ANSI/IEEE C57.98-1986.

c. Procedure. The proposed transformer replacement will be two winding, single-phase, 60-Hz, FOA cooled units, 65 °C rise, connected delta/wye, with the following ratings:

Transformer bank: Three-1ϕ, 46,000 *kVA*,
13.2 *kV*/230 *kV*.

These transformers are considered to be a "replacement-in-kind."

(1) *Transformer high-voltage basic impulse insulation levels (BIL's).*

(a) Line BIL characteristics. The Power Marketing Authority's (PMA's) transmission line, transformer high-voltage insulation, high-voltage bushing BIL characteristics, and surge arrester duty-cycle ratings are as follows:

<u>230-*kV* System:</u>

- Transmission line: approximately 750 *kV* BIL
- Transformer high-voltage insulation: typically 650 *kV* BIL
- High-voltage bushings: typically 750 *kV* BIL
- Surge arrester rating: typically 180 *kV* duty-cycle rating

(b) This study will analyze transformer high-voltage BIL levels of 650 *kV*, 750 *kV*, and 825 *kV*, for the 230-*kV* transmission line, and determine the correct level of protection.

(2) *Transformer impulse curves.*

(a) Front-Of-Wave (FOW) withstand voltage.

As indicated by ANSI C62.2, the FOW strength range should be between 1.3 and 1.5 times the BIL rating, with time-to-chop occurring at 0.5 μs. For the purposes of this coordination study, an FOW strength of 1.4 times BIL shall be used.

Table B-1
FOW Withstand Voltage

Line Voltage, kV	BIL Rating, kV	FOW Strength, kV
230	650	910
230	750	1050
230	825	1155

(b) Chopped-wave (CWW) withstand voltage.

Chopped-wave withstand voltage levels for different transformer high-voltage BIL ratings are listed in Table 5 of ANSI/IEEE C57.12.00. These levels correspond to 1.1 × BIL, and the time-to-chop occurs at 3.0 μs.

Table B-2
CWW Withstand Voltage

Line Voltage, kV	BIL Rating, kV	CWW Strength, kV
230	650	715
230	750	825
230	825	905

(c) Full-wave (BIL) withstand voltage.

The full-wave withstand voltage is equivalent to the high-voltage BIL rating of the transformer. This withstand voltage occurs as a straight line from 8 to 50 μsec.

(d) Switching impulse level (BSL) withstand voltage.

Switching impulse withstand voltage levels for different transformer high-voltage BIL ratings are listed in Table 5 of ANSI/IEEE C57.12.00. These levels correspond to 0.83 × BIL, and extend from 50 to 2,000 μsec.

Table B-3
BSL Withstand Voltage

Line Voltage, kV	BIL Rating, kV	BSL Strength, kV
230	650	540
230	750	620
230	825	685

(e) Applied voltage test level.

Applied voltage test levels for different transformer high-voltage BIL ratings are listed in Table 5 of ANSI/IEEE C57.12.00.

Table B-4
APP Voltage

Line Voltage, kV	BIL Rating, kV	APP Strength, kV
230	650	275
230	750	325
230	825	360

(f) Transformer impulse curve generation. The transformer impulse curve is generated as indicated in Figure 3 of ANSI C62.2. As discussed in Figure 3:

> It is not possible to interpolate exactly between points on the curve. Good experience has been obtained with the assumptions implicit in the preceding rules: (a) The full BIL strength will apply for front times between 8 and 50 µs. (b) Minimum switching surge withstand occurs between 50 and 2,000 µs. Refer to the attached plot of the transformer impulse curves located at the end of this study.

(3) *Surge arrester type and sizing.*

(a) General. The objective for surge protection of a power system is to achieve at a minimum cost an acceptably low level of service interruptions and an acceptably low level of transformer failures due to surge-related events.

(b) Arrester type. Surge arresters utilizing metal-oxide (such as zinc-oxide) valve (MOV) elements will be used due to the extreme improvement in nonlinearity as compared to arresters with silicon-carbide valve elements. This nonlinear characteristic of the voltage-current curve provides better transformer protection and improves the arrester's thermal stability.

(c) Arrester class. Station class arresters shall be utilized, based on system line voltage of 230 *kV*.

(d) Arrester sizing. It is desirable to select the minimum-sized arrester that will adequately protect the transformer insulation from damaging overvoltages, while not self-destructing under any reasonably possible series of events at the location in the system. Since the metal-oxide valve in MOV arresters carries all or a substantial portion of total arrester continuous operating voltage, the most important criterion for selection of the minimum arrester size is the continuous operating voltage. Selection of a size for an arrester to be installed on grounded neutral systems is based upon:

• The maximum continuous operating voltage (MCOV), line-to-neutral, at the arrester location computed as the maximum system voltages divided by root-three.

• The assumption that the system is effectively grounded where a fault is expected to initiate circuit breaker operation within a few cycles.

(e) Minimum arrester sizing for system line voltage. Based upon ANSI C57.12.00, the relationship of nominal system voltage to maximum system voltage is as follows:

Nominal System Voltage	Maximum System Voltage
230 *kV*	242 *kV*

(4) The minimum arrester sizing in MCOV for the system line voltage shall, therefore, be as follows:

• Arrester MCOV rating = 242 $kV / \sqrt{3}$ = 139.7 $kV_{1\text{-}n}$

• This calculated arrester rating of 139.7 $kV_{1\text{-}n}$ MCOV for the 230-*kV* line voltage corresponds to a standard arrester voltage rating of 140 $kV_{1\text{-}n}$ MCOV and a duty-cycle voltage of 172 $kV_{1\text{-}n}$, as outlined in Table 1 of ANSI C62.11.

(5) Line voltages at the powerhouse are commonly operated between the nominal and maximum system voltages. Based on this, the surge arrester should be sized somewhat higher than the maximum system line-to-neutral voltage rating of the line to avoid overheating of the arrester during normal operating conditions. The arrester rating chosen shall be one MCOV step higher than the recommended MCOV for grounded neutral circuits. The following arrester MCOV values have been chosen:

- Arrester MCOV rating = 144 *kV*
- Arrester duty-cycle rating = 180 *kV*

B-4. Surge Arrester Impulse Curves

For the purposes of this coordination study, surge arrester voltage withstand levels shall be assumed to correspond to typical manufacturer's data. These voltage withstand voltage levels shall be used for the generation of the arrester curves and the coordination study. Gapped design MOV surge arresters are typically used for distribution class transformers. The gapless design surge arrester shall be addressed in this study, since it represents a typical MOV type arrester suitable for these applications.

a. Maximum 0.5 µs discharge voltage (FOW). The discharge voltage for an impulse current wave which produces a voltage wave cresting in 0.5 µs is correlative to the front-of-wave sparkover point. The discharge currents used for station class arresters are 10 kA for arrester

MCOV from 2.6 through 245 *kV*. As taken from the manufacturer's protective characteristics,

230 *kV* line voltage (144 *kV* arrester MCOV)

Maximum 0.5 μs discharge voltage = 458 *kV*

b. Maximum 8 × 20 μs current discharge voltage (LPL). Discharge voltages resulting when ANSI 8 × 20 μs current impulses are discharged through the arrester are listed in the manufacturer's data from 1.5 kA through 40 kA. For coordination of the 8 × 20 μs current-wave discharge voltage with full-wave transformer withstand voltage, a value of coordination current must be selected. To accurately determine the maximum discharge currents, the PMA was contacted and the following line fault currents were obtained:

Transmission Line (230 *kV*):
3ϕ fault................17010 Amperes
line-ground fault..15910 Amperes

c. Maximum switching surge protective level (SSP). The fast switching surge (45 × 90 μs) discharge voltage defines the arresters' switching surge protective level. As taken from the manufacturer's protective characteristics,

230 *kV* line voltage (144 *kV* arrester MCOV)

Maximum switching surge protective level at classifying 1,000 ampere current level = 339 *kV*.

d. 60-Hz temporary overvoltage capability. Surge arresters may infrequently be required to withstand a 60-Hz voltage in excess of MCOV. The most common cause is a voltage rise on unfaulted phases during a line-to-ground fault. For the arrester being addressed for the purposes of this coordination, the arrester could be energized at 1.37 × MCOV for a period of 1 min.

230-*kV* line voltage (144-*kV* arrester MCOV)

60-Hz temporary overvoltage capability:
144 *kV* × 1.37 = 197.3 *kV*

B-5. Transformer High-Voltage BIL/Surge Arrester Coordination

a. Coordination between MOV arresters and transformer insulation is checked by comparing the following points of transformer withstand and arrester protective levels on the impulse curve plot:

Table B-5
Surge Arrester Coordination

MOV Arrester Protective Level	Transformer Withstand Level
Maximum 0.5 μs discharge voltage - "FOW"	Chopped-wave withstand - "CWW"
Maximum 8 × 20 μs current discharge voltage - "LPL"	Full-wave withstand - "BIL"
Maximum switching surge 45 × 90 μs discharge voltage - "SSP"	Switching surge withstand - "BSL"

b. At each of the above three points on the transformer withstand curve, a protective margin with respect to the surge arrester protective curves is calculated as:

$$\%\ PM = \left[\frac{(\text{Transformer Withstand})}{(\text{Protective Level})} - 1\right] \times 100$$

c. The protective margin limits for coordination, as specified in ANSI C62.2, are as follows:

(1) % PM (CWW/FOW) ≥ 20

(2) % PM (BIL/LPL) ≥ 20

(3) % PM (BSL/SSP) ≥ 15

d. The protective margins for the MOV arresters selected yield protective margins of:

(1) *Transformer BIL = 650 kV.*

(a) % PM (CWW/FOW) = (715 *kV*/458 *kV* - 1) × 100 = 56%

(b) % PM (BIL/LPL) = (650 *kV*/455 *kV* - 1) × 100 = 43%

(c) % PM (BSL/SSP) = (540 *kV*/339 *kV* - 1) × 100 = 59%

(2) *Transformer BIL = 750 kV.*

(a) % PM (CWW/FOW) = (825 *kV*/458 *kV* - 1) × 100 = 80%

(b) % PM (BIL/LPL) = (750 *kV*/455 *kV* - 1) × 100 = 65%

(c) % PM (BSL/SSP) = (620 *kV*/339 *kV* - 1) × 100 = 83%

(3) *Transformer BIL = 825 kV.*

(a) % PM (CWW/FOW) = (905 *kV*/458 *kV* - 1) × 100 = 98%

(b) % PM (BIL/LPL) = (825 *kV*/455 *kV* - 1) × 100 = 81%

(c) % PM (BSL/SSP) = (685 *kV*/339 *kV* - 1) × 100 = 102%

d. Summary.

(1) As noted from the transformer BIL / surge arrester coordination plots (Figure B-1), the minimum protective margins are much greater than the design standards, due to the better protective characteristics of MOV surge arresters.

(2) A high-voltage winding BIL rating of 750 *kV* BIL for the 230-*kV* nominal system voltage shall be selected for the transformers. These BIL selections will provide the following advantages: (a) reduction in transformer procurement costs, (b) reduction in transformer losses, (c) better coordination with the BIL rating structure of the system, and (d) reduction in the physical size of the transformer. Item (d) is due consideration because of vault size limitations.

B-6. Sample Study B2, Transformer Bushings Rating

a. Objective. The objective of this study is to determine the proper ratings for the bushings and bushing current transformers on the replacement generator step-up (GSU) transformers.

b. References. The following references were used in the performance of this study. Complete citations can be found in Appendix A of this document, "References."

(1) ANSI C76.1-1976 / IEEE Std. 21-1976.

(2) ANSI C76.2-1977 / IEEE Std. 24-1977.

(3) ANSI C57.13-1978.

(4) Main Unit Generator Step-up Transformer Replacement, Transformer *kVA* Rating Study.

(5) Main Unit Generator Step-up Transformer Replacement, BIL / Surge Arrester Coordination Study.

c. Procedure. As summarized in the referenced studies, the transformers shall be rated as follows:

46,000 *kVA*
13.2 *kV* △/230 *kV* Y
750 *kV* High-Voltage Winding BIL
110 *kV* Low-Voltage Winding BIL

d. Bushing ratings and characteristics. As outlined in IEEE Std. 21-1976, performance characteristics based upon definite conditions shall include the following:

- Rated maximum line-to-ground voltage
- Rated frequency
- Rated dielectric strengths
- Rated continuous currents

The bushings will not be subject to any unusual service conditions.

(1) *Rated maximum line-to-ground voltage.*

(a) Based upon ANSI C57.12.00, the relationship of nominal system voltage to maximum system voltage is as follows:

Nominal System Voltage	Maximum System Voltage
230 *kV*	242 *kV*

(b) The maximum line-to-ground voltage is therefore:

Maximum System Voltage	Maximum Line-To-Ground Voltage
242 *kV*	139.7 *kV*

(c) Line voltages are commonly operated between the nominal and maximum system voltages. Based on this, the selection of maximum line-to-ground voltages will be chosen as 5 percent higher than the ANSI suggested values to avoid overheating of the bushings during normal operating conditions. This leads to bushing selections with the following Rated Maximum Line-To-Ground Voltage, Insulation Class, and BIL characteristics:

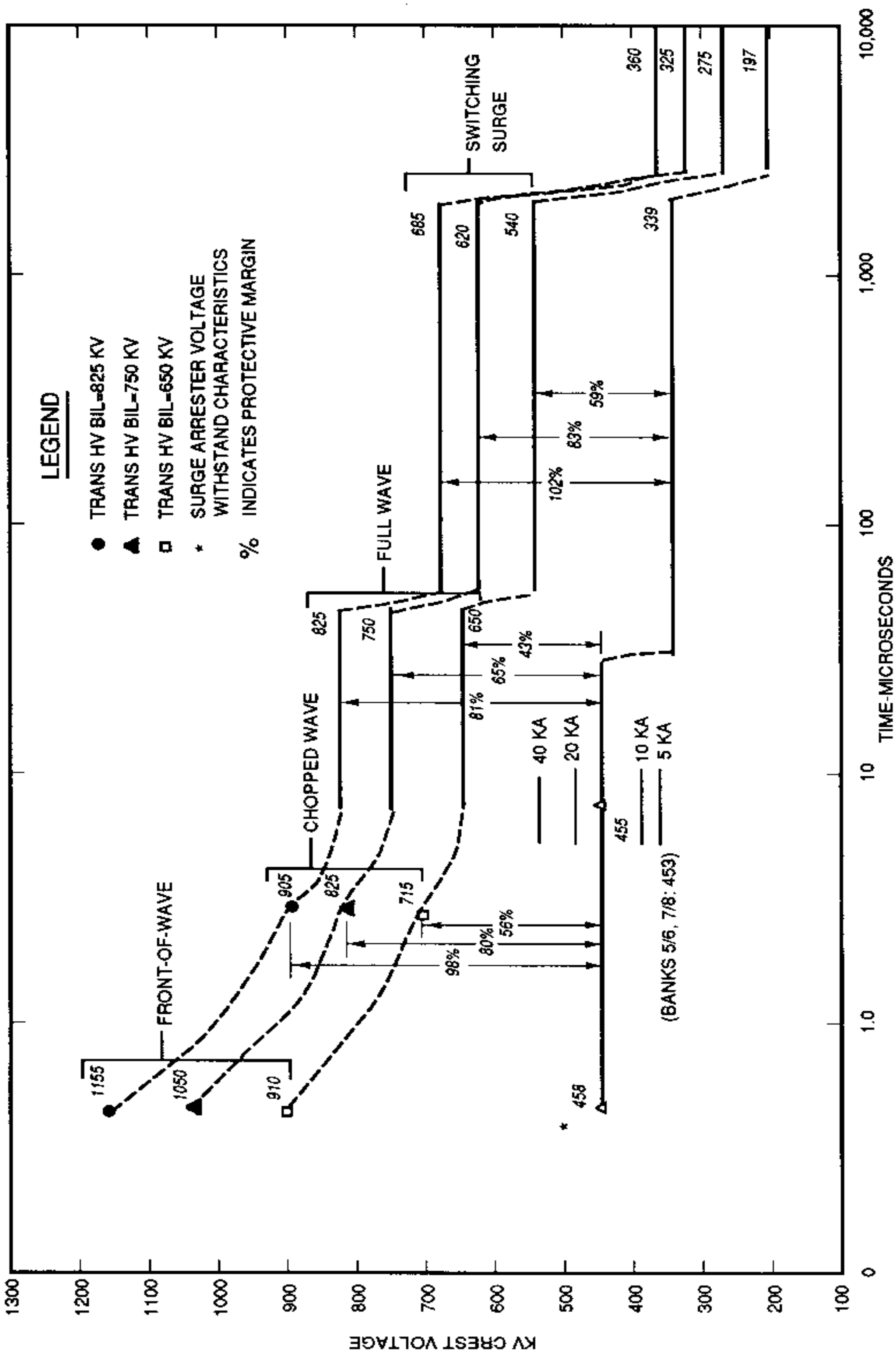

Figure B-1. Transformer BIL/Surge Arrester Coordination Plots

- Line Voltage: 230 *kV*

- Bushing Insulation Class: 196 *kV*

- Bushing BIL: 900 *kV*

- Rated Maximum Line-to-Ground Voltage: 146 *kV*

(d) The low-voltage terminal bushings shall be insulated at the same BIL as the generator windings, i.e., 110 *kV* BIL. This corresponds to an insulation class of 15 *kV*.

(e) The neutral terminal bushings shall be insulated at 150 *kV* BIL, corresponding to an insulation class of 25 *kV*.

(2) *Rated frequency.* The frequency at which the bushings shall be designed to operate is 60 Hz.

(3) *Rated dielectric strengths.* The rated dielectric strengths for the transformer bushings, expressed in terms of specific values of voltage withstand tests, shall be as follows:

(a) <u>230 *kV* system high-voltage bushings.</u>

- 60 Hz, 1-min Dry Voltage Withstand Test: 425 *kV* rms

- 60 Hz, 10-sec Wet Voltage Withstand Test: 350 *kV* rms

- Full Wave Impulse Voltage Withstand Test: 900 *kV*

- Chopped Wave Impulse - *kV* Crest, 2μsec Withstand: 1160 *kV*

- Chopped Wave Impulse - *kV* Crest, 3μsec Withstand: 1040 *kV*

(b) <u>13.2 *kV* low-voltage bushings.</u>

- 60 Hz, 1-min Dry Voltage Withstand Test: 50 *kV* rms

- 60 Hz, 10-sec Wet Voltage Withstand Test: 45 *kV* rms

- Full Wave Impulse Voltage Withstand Test: 110 *kV*

- Chopped Wave Impulse - *kV* Crest, 2μsec Withstand: 142 *kV*

- Chopped Wave Impulse - *kV* Crest, 3μsec Withstand: 126 *kV*

(c) <u>Neutral bushings.</u>

- 60 Hz, 1-min Dry Voltage Withstand Test: 60 *kV* rms

- 60 Hz, 10-sec Wet Voltage Withstand Test: 50 *kV* rms

- Full Wave Impulse Voltage Withstand Test: 150 *kV*

- Chopped Wave Impulse - *kV* Crest, 2μsec Withstand: 194 *kV*

- Chopped Wave Impulse - *kV* Crest, 3μsec Withstand: 172 *kV*

(4) *Rated continuous currents.*

(a) The following are the rated currents for the transformer bank, based upon the maximum *k*VA generating capacity of each generating unit:

- Two generators shall be connected to the transformer bank. The maximum *k*VA rating of each generator is 69,000 *k*VA. The total of the generator rated currents for these units is, therefore:

$$I = \frac{2S_{3\phi}}{\sqrt{3}\,V_L} = \frac{(2)\,69{,}000\,kVA}{\sqrt{3}\,(13.8\,kV)} = 5{,}774\ Amps$$

- Total rated low-voltage terminal current for delta connected transformers:

$$I_{\triangle} = \frac{I}{\sqrt{3}} = \frac{5{,}774\ Amps}{\sqrt{3}} = 3{,}334\ Amps$$

- Rated line current:

$$I_L = 5{,}774\ Amps \times \frac{13.2\,kV}{230\,kV} = 331\ Amps$$

(b) Based on the above data, the suggested minimum bushing rated current requirements shall be as follows:

- High-Voltage Bushing Minimum Current Rating: 400 Amperes

- Neutral Bushing Minimum Current Rating: 400 Amperes

- Low-Voltage Bushing Minimum Current Rating: 3,500 Amperes

e. Bushing current transformer (CT) ratings and characteristics. Two standard multi-ratio bushing-type CT's for relaying service shall be installed in each of the 230-*kV* transformer high-voltage bushings for the bank, conforming to accuracy classification 'C', rated 400/5. These CT's shall be used for transformer differential relaying and line protective relaying.

B-7. Sample Study B3, Transformer Efficiency

a. Objective. The objective of this study is to estimate the transformer efficiencies for the proposed replacement generator step-up (GSU) transformers.

b. References. The following references were used in the performance of this study. Complete citations can be found in Appendix A of this document, "References."

(1) Main Unit Generator Step-up Transformer Replacement, Transformer *k*VA Rating Study.

(2) Main Unit Generator Step-up Transformer Replacement, BIL/Surge Arrester Coordination Study.

(3) Westinghouse Electric Corporation. 1964 (located at end of study).

c. Procedure. The calculations for estimating the transformer losses and efficiency calculations shall be based on the Westinghouse Technical Data Bulletin No. 48-500. The following steps will be used in determining this data:

(1) Determine the insulation level of the transformer.

(2) Determine the equivalent two winding 65 °C reference product factors.

(3) Determine the basic product factor from the Table A: 65 °C reference product factors.

(4) Adjust for special features.

(5) Determine the ratio of losses.

(6) Determine the losses.

(7) Determine transformer estimated efficiency.

*d. Transformer bank: 46,000 k*VA, 1ϕ, 13.2 *kV* △/230 *kV* Y, FOA cooled transformers.

(1) *Transformer BIL rating.*

(a) Low-voltage windings: 110 *kV* BIL.

(b) High-voltage windings: 750 *kV* BIL.

(2) *Equivalent two-winding 65 °C self-cooled MVA.* For FOA type cooling rated at 65 °C, the specified *MVA* is for self-cooling.

(3) *Basic product factor determination (P_e).* Basic reference product factor:

$$P_e = A\sqrt{MVA} + \frac{B}{\sqrt{MVA}}$$

(a) As taken from Table A, A = .0001590, B = .2564

(b) Conversion of the *MVA*(1ϕ) to *MVA*(3ϕ) is required to calculate the product factor.

$MVA(3\phi) = 2 \times MVA(1\phi) = 2 \times 46\ MVA = 92\ MVA$

(c) Therefore, the base product factor (P_e) is:

$$P_e = .0001590\sqrt{92} + \frac{.2564}{\sqrt{92}} = .028257$$

(4) *Adjust P_e for % adders (P_r).* The base product factor calculated in (c) should be adjusted further for special features. The adjusted base product factor, P_r, is calculated as follows:

$$P_r = (1 + \frac{\Sigma PercentAdditions}{100}) \times P_e$$

(a) From Table B, on page 12 of the Westinghouse document, the percent additions are:

Front of Wave Impulse Test: 5%

(b) Final adjusted base product factor:

$P_r = .028257 \times (1+.05) = .029669$

(5) *Loss ratio (R).* The ratio of losses (NL *kW*/L *kW*), applying to the reference product factors, for transformers with the high-voltage winding BIL between 550 and 750 *kV*, is calculated as follows:

R = 2.75 - .182 1n *MVA*

R = 2.75 - .182 ln 46 = 2.053

(6) *Determination of losses.*

(a) The percent no-load loss is given by:

$$\%Fe = \sqrt{\frac{P}{R}} = \sqrt{\frac{.029669}{2.053}} = .120214$$

(b) No-load loss is given by:

$$No\text{-}Load\ Loss = \frac{MVA}{100} \times \%Fe$$

$$= \frac{46}{100} \times .120214 = .055299\ MW$$

No-Load Loss = 55.30 *kW*

(c) Total loss is given by:

Total Loss = (R+1) × No-Load Loss

Total Loss = (2.053 + 1) × 55.30 *kW* = 168.83 *kW*

(d) Load loss is given by:

Load Loss = Total Loss - No-Load Loss
= 168.83 *kW* - 55.30 *kW*

Load Loss = 113.53 *kW*

(7) *Estimated efficiency* (η). The transformer estimated efficiency is given by:

$$\eta = \frac{MVA}{MVA + Total\ Losses} \times 100\%$$

$$= \frac{46}{46 + .168830} \times 100\% = 99.63\%$$

B-8. Sample Study B4, Transformer Loss Evaluation

a. Objective. The objective of this study is to establish the loss evaluation and penalty factors, and determine an auxiliary cooling loss evaluation factor, for use in the construction specifications for the new main unit generator step-up replacement transformers.

b. References. The following reference was used in the performance of this study. A complete citation can be found in Appendix A of this document, “References.”

(1) “Main Unit Generator Step-Up Transformer Replacement, Transformer Efficiency Study.”

(2) Guide Specification CE-2203. Power Transformers.

c. Discussion.

(1) *Pertinent values for computations.* The following sample values will be used in the computations for loss evaluation:

(a) Value of replacement energy: 15.94 mills/KW-hr

(b) Value of replacement capacity: $267,800/MW-yr = $30.57/KW-yr

(c) Alternative cost of Federal financing interest rate: 8.5%

(d) Plant capacity factor: 54%

(2) *Determination of rates of evaluation.* The evaluation of transformer efficiency for use in determining award of the contract should be based on the same value per *kW* of loss used in determining the evaluation of efficiency of the associated main generators. This value of one kilowatt of loss is the capitalized value of the annual capacity and energy losses based on the average annual number of hours of operation. The transformer load used for efficiency evaluation should correspond approximately to the generator load used for evaluation of generator efficiency. For class FOA transformers, 87 percent of rated load at 1.0 power factor shall be used.

Westinghouse Electric Corporation
Medium Power Transformer Division
Sharon, Pa. 16146

Large Power Transformer Division
Muncie, Indiana 47302

Technical Data
48-500

Page 1

September 15, 1981
Supersedes TD 48-660, pages 1-24,
dated November 23, 1964

Mailed to: E, D, C/2091, 2094/DB

Power Transformers

Table of Contents

General Information
The information and instructions contained in this technical data cover power transformers rated as follows: Oil-Immersed, Self-Cooled, Forced-Air Cooled, and Forced-Oil Cooled.

The kVA ratings below are self-cooled. 2500 through 10000 kVA, 3-Phase, greater than 350 kV BIL or with Load Tap Changing (LTC), 10001 kVA and larger, 3-Phase, all Basic Impulse Levels (BIL) with or without LTC, 1667 through 3333 kVA, 1-Phase, 450 through 750 kV BIL or with LTC, 3334 and larger, 1-Phase, all Basic Impulse Levels (BIL) with or without LTC.

Proper Selection
The basic economic considerations in making the proper selection of a power transformer are first cost and operating costs (transformer losses).

In order for the transformer designer to select the proper losses, he must first know the dollars per kilowatt loss that the user of the transformer evaluates both the iron (No-Load) losses and the conductor (Load) losses and at what kVA load these values will be used to evaluate the losses.

The losses determined from the loss product factor and loss ratio rules in this technical data are for reference only and indicate the approximate losses of a transformer on which there is no loss evaluation or when losses are evaluated at values which result in an efficiency multiplier of 1.00 from Rule 2 in Price List 48-500.

Section V

Loss Product Factor and Loss Ratio

The reference product factors are based on the premise that the standard transformer is a 65°C rise transformer and the load losses are to be tested at a standard reference temperature of 85°C in accordance with ANSI C57.12.00. The transformer can however deliver the specified output Kva at other average temperature rises by the addition of the required cooling apparatus. For instance, by the addition of the necessary cooling apparatus the transformer can deliver the specified output at an average winding temperature rise of 55°C. Once this transformer has been adjusted to be a 55°C rise transformer it will have a supplemental 65°C rise rating equal to 1.12 times the 55°C rating.

The equivalent 65°C two-winding parts to be used in calculating the loss product factor is the 65°C self-cooled Kva two-winding parts of a transformer specified to deliver the required output Kva at an average winding temperature rise of 65°C or the self-cooled Kva parts calculated by using the output Kva specified at 55°C rise for a 55°C/65°C transformer. The losses for the 55°C rise transformer are adjusted to be tested at a 75°C reference temperature rather than 85°C by dividing the calculated load losses by 1.04. The load losses at the 65°C rise supplemental rating of a 55°/65°C transformer are 1.2544 (1.12 squared) times the load losses at the 55°C rise rating times 1.04 to correct the losses to the reference temperature of 85°C.

In calculating the loss product factor and loss ratio for a power transformer the following procedure must be followed:

First: Determine the insulation level from section III.

Second: Determine the equivalent two winding 65°C self-cooled mva.*

Third: Determine the basic product factor from the table A: 65°C reference product factors.

Fourth: Adjust for special features.

Fifth: Determine the ratio of losses.

Sixth: Determine the losses.

*The equivalent two-winding parts are the sum of the mva's of all the windins divided by two.

To calculate the equivalent 2 winding Kva parts to be used in developing the basic product factor for an autotransformer use the following formulas to calculate the Kva's of the windings.

Series winding Kva =

$$(HV^{*}\ \text{max.} - LV^{*}\ \text{min}) \left(\frac{\text{OA Kva}}{HV^{**}\ \text{Min}} \right)^{*}$$

Common winding Kva =

$$LV^{*}\ \text{max} \left(\frac{\text{OA Kva}}{LV^{**}\ \text{Min}} - \frac{\text{OA Kva}}{HV^{**}\ \text{Max}} \right)$$

Tertiary winding Kva = .35 × largest of series or common

*Do not use LTC tap voltages, use the de-energized tap voltages in Kv.

**Use LTC tap voltages and/or de-energized tap voltages, in Kv, that determine this voltage at which full nameplate Kva occurs as either input or output.

Step 1: Base Product Factor

The base product factor, based on the equivalent 65°C self-cooled two-winding mva parts, is calculated from Table A by selecting the proper A and B factor for the proper BIL and the following formula.

$$\text{Product Factor} = A\sqrt{MVA} + \frac{B}{\sqrt{MVA}}$$

The calculated product factor should be rounded to the nearest five decimal places.

Table A:
65°C Reference Product Factors
(3-phase transformers)

Product factors are to be based on the equivalent 65°C two-winding parts.

BIL-Kv	A	B
110	.0001760	.2300
150	.0001758	.2317
200	.0001750	.2337
250	.0001745	.2358
350	.0001740	.2399
450	.0001730	.2440
550	.0001700	.2481
650	.0001660	.2522
750	.0001590	.2564
825	.0001500	.2594
900	.0001380	.2625
1050	.0001240	.2695
1175	.0001070	.2800
1300	.0000870	.2940
1425	.0000640	.3260
1550	.0000420	.3510
1675	.0000095	.3880
1800	−.0000392*	.4299
1925	−.0000744*	.4750
2050	−.0001134*	.5219

*These are negative numbers.

55°C Losses
No-load losses are the same as 65°C no-load losses
Load losses = 65°C load losses/1.04

Single-phase transformer product factors
Multiply the 1φ MVA times 2, then use the result to calculate the product factor from the 3φ table.

Step 2: Percentage Additions to Base Product Factor

The base product factor calculated in accordance with Step 1, should be adjusted further for special features in accordance with Table B. The summation of all the percent additions for special features is to be multiplied times the base product factor as follows:

$$\left(1 + \frac{\Sigma\ \text{Percent Additions}}{100} \right) \times \text{Base Product Factor}$$

This determines the final adjusted base product factor.

Table B
Percentage Additions to Base Product Factor

	% Adders
More than two windings	
3-windings	15
≥4-windings	20
Ground Neutral Service**	
≤350 (BIL)*	0
450	− 1.0
550	− 1.5
650	− 2.0
750	− 2.5
825	− 2.5
900	− 3.0
Windings other than H.V. BIL other than Auto:	
110	0
150	2.0
200	4.0
250	8.0
350	16.0
450	22.0
550	29.0
650	36.0
750	42.0
825	47.0
900	52.0
BIL of Common Winding of Autotransformer:	
110	0
150	2.0
200	4.0
250	6.0
350	11.0
450	14.0
550	17.0
650	20.0
750	23.0
825	25.0
900	27.0
Special Front of Wave Impulse Test	5.0
Split HV or LV Winding	2.0
LTC	10.0 or % reg.* if greater
Series Multiple:	
2 Multiples	5
3 Multiples	10
4 Multiples	12
Station Auxiliary If Rule 5K in Price List 48-500 applies.	−15

*e g ±15% LTC would add 15.0.
**Does not apply to autotransformers.

Step 3: Multiplier on Adjusted Base Product Factor for Other Than Two-Winding Transformer

The base adjusted product factor, calculated in accordance with Steps 1 and 2, should be adjusted for other than two-winding transformers and autotransformers if applicable, to adjust for the loading Kva and equivalent self-cooled two-winding Kva parts. The product factor, Pr, determined in accordance with this step will be the product factor of the losses at the **OA nameplate rating.**

Pr = Pe × K

Where:

Pr = Product factor corresponding to the OA nameplate rating, or equivalent if the transformer is FOA only*

Pe = Base reference product factor for the equivalent self-cooled two-winding Kva parts, calculated in accordance with Steps 1 and 2.

$$K = A \times \left(\frac{\text{equivalent self-cooled two-winding kva parts}}{\text{OA Nameplate rating}} \right)^2$$

Where; for autotransformer, A = .65
for other than autotransformer, A = .85

* To obtain the load losses at the FOA rating, multiply the load losses calculated with this product factor by 2.78.

Loss Ratio: The ratio of losses (NL KW/L kw) applying to the reference product factors can be calculated from table C for the standard 65°C rise unit. The 55°C rise loss ratio is the 65°C rise ratio + 1.04.

Table C. Loss Ratios
BIL KV of the highest voltage winding

≤350	>350 ≤550	>550 ≤750	>750 ≤900	>900 ≤1175	>1175 ≤1425	>1425
5.45-.516 Ln MVA	3.82-.270 Ln MVA	2.75-.182 Ln MVA	2.50-.111 Ln MVA	2.26-.078 Ln MVA	2.13-.060 Ln MVA	2.08-.058 Ln MVA

where:
Ln MVA is the natural logarithm of the MVA

The loss ratio calculated from Table C must be further adjusted in accordance with Table D. Any multiplier adjustments will be made to the multiplier adjusted ratio by multiplying by:

$$\left(1 + \frac{\Sigma \text{ Percent adders}}{100}\right)$$

Table D: Adjustment to Loss Ratio

Special Feature	Multiplier	% Adder
Frequency 50 Hertz	1.2	
Special Impedance	$\sqrt{\frac{\%Z\ spec.}{\%Z\ Std.}}$	
Over Excitation percent above standard for either no-load or full-load voltage		
5%		25
10%		35
15%		45
20%		60
25%		70
Reduction in Sound level Based on loss evaluation in $/kw applied to no-load loss		
≤1000		2 per db
>1000 ≤2000		1 per db
>2000		0
Station Auxiliary If Rule 5K in Price List 48-500 applies, add		35①
Autotransformers	$\sqrt{r}$②	
LTC Voltage Regulation Through the Magnetic Circuit. Percent Regulation		
5		25
10		35
15		45

① Do not make any further addition for over excitation.

② $r = \frac{HV_{mid} - LV_{rated}}{HV_{mid}}$

Determination of Losses

The percent no load loss (%Fe) and the percent load loss (%Cu) may be determined from the final product factor (P) and the loss ratio (R) by using the following formula:

$$\% \text{ Fe} = \sqrt{\frac{P}{R}} \qquad \% \text{ Cu} = R \times \% \text{ Fe}$$

$$\text{No load loss (kw)} = \frac{\text{kva}}{100} \times \% \text{ Fe}$$

$$\text{Total loss (kw)} = (R + 1.0) \times \text{no load loss}$$

Power Required for Fans and Pumps

When it is required that the losses due to the fans and pumps be guaranteed they must be given separately from the transformer losses.

The loss for the fans and pumps is based on the total transformer loss at the fan-cooled or forced-cooled rating and shall be not less than the following:

for standard forced-air cooling
(OA/FA) .... 2% (max.)
for OA/FA/FA .... 2% (max.)
for OA/FOA/FOA .... 5% (max.)
for forced-oil cooled with air cooler
(FOA) .... 5% (max.)
for forced-oil-cooled with water
cooler (FOW) .... 3½% (max.)

Determination of Loss Level

The evaluation $/kw for no-load and load losses will affect the optimized design losses of a transformer. Typically, the dollar evaluations shown in Table E, will result in approximate percent product factors and loss ratios as shown. When estimating the efficiency multiplier for a design that falls outside the usual grid position for the specified evaluation dollars use the efficiency multiplier in table 2a (PL 48-500) corresponding to the design's actual percent product factor grid position in Table E.

Table E

(OA) Load② $/kw / No Load $/kw	55°C	≤650	>650 ≤1300	>1300 ≤1950	>1950 ≤2600	>2600 ≤3900	>3900 ≤5200	>5200 ≤
	65°C	≤500	>500 ≤1000	>1000 ≤1500	>1500 ≤2000	>2000 ≤3000	>3000 ≤4000	>4000 ≤
≤500	% PF	100	74	68	63	59	55	52
	R①	3.5	3.4	3.3	3.0	2.8	2.6	2.4
>500 ≤1000	% PF	75	70	64	61	57	54	51
	R①	3.6	3.5	3.4	3.1	2.9	2.7	2.5
>1000 ≤1500	% PF	71	67	61	59	55	52	50
	R①	3.7	3.6	3.5	3.3	3.1	2.8	2.5
>1500 ≤2000	% PF	68	63	60	57	54	52	50
	R①	3.7	3.6	3.5	3.3	3.1	2.8	2.5
>2000 ≤2500	% PF	66	62	59	56	54	51	49
	R①	3.8	3.7	3.6	3.4	3.2	2.9	2.6
>2500 ≤3000	% PF	64	61	58	55	53	51	49
	R①	3.8	3.7	3.6	3.4	3.2	2.9	2.6
>3000 ≤4000	% PF	62	60	57	55	52	51	49
	R①	3.9	3.8	3.7	3.5	3.3	3.0	2.7
>4000 ≤5000	% PF	60	58	55	53	52	50	48
	R①	4.0	3.9	3.8	3.6	3.4	3.1	2.8
>5000	% PF	58	56	54	52	51	50	48
	R①	4.1	4.0	3.9	3.7	3.5	3.2	2.9

① For autotransformers, the loss ratio must be multiplied by $\sqrt{\frac{\text{HV mid} - \text{LV rated}}{\text{HV mid}}}$

② For FOA units, convert load $/kw to an equivalent OA basis by multiplying ($/kw) × 2.78.

Exciting Current (Estimated)

For estimated values of exciting current and no load losses for 60 cycle transformers use values calculated from the following table:

Percent Rated Voltage	Percent Exciting Current				Percent No-Load Loss			
	No-Load Loss Evaluation-$/kw				No-Load Loss Evaluation-$/kw			
	≤500	>500 ≤2500	>2500 ≤5000	>5000	≤500	>500 ≤2500	>2500 ≤5000	>5000
80	2A	1.5A	1A	0.8A	0.54A	0.59A	0.62A	0.65A
90	4A	3A	2A	1.2A	0.72A	0.77A	0.80A	0.82A
100	12A	6A	4A	2A	1.00A	1.00A	1.00A	1.00A
105	23A	10A	6A	3A	1.25A	1.21A	1.15A	1.12A
110	43A	16A	9A	4A	1.80A	1.40A	1.33A	1.25A
117.5	....	50A	22A	6A	....	2.10A	1.70A	1.45A

where A is percent no load loss (% Fe) determined above. For frequency other than 60 cycles, multiply the 60 cycle percent exciting current obtained above by:

50 cycles 1.1

(a) The rate of evaluation for efficiency is calculated as present worth, as follows:

- R = rate of evaluation
- EV = energy value
- CV = capacity value
- CF = capacity factor
- PWF = present worth factor

So,

$$R = (PWF)\,((365)\,(24)\,(EV)\,(CF) + CV)$$

The present worth factor (PWF) for 35 years at 8.5% is:

$$PWF = (\frac{P}{A}, 8.5\%, 35) = \frac{(1+.085)^{35}-1}{.085(1+.085)^{35}} = 11.088\,YR$$

$$R = (11.088YR) \times ((365\frac{DAYS}{YEAR}) \times (24\frac{HOURS}{DAY})$$
$$\times (.01594\frac{\$}{KW-HR}) \times (.54) + 30.57\frac{\$}{KW-YR})$$
$$= 1{,}175\frac{\$}{KW}$$

(b) Transformer efficiency and losses. Transformer input shall be based upon 87 percent of rated load at 1.0 power factor of the connected generators. The transformer bank has two generators connected, each rated at 69,000 kVA at 1.0 power factor. The total input to each single-phase transformer under these conditions is therefore:

$$Input = \frac{(2) \times (69{,}000\ kVA) \times (1.0\ pf) \times (0.87)}{3\ transformers}$$
$$= 40{,}020\ kW$$

Transformer output shall be based upon the specified efficiency of 99.63 percent:

$$Output = 40{,}020\ kW \times (99.63\%) = 39{,}872\ kW$$

Transformer loss is therefore

$$Loss = 40{,}020\ kW - 39{,}872\ kW = 148\ kW$$

(c) Rate of evaluation for each 1/100% of transformer efficiency. Transformer losses per 1/100% of transformer efficiency is:

$$Loss\ per\ 1/100\% = \frac{148\ kW}{(100 - 99.63) \times (100)} = 4.00\ kW$$

The rate of evaluation per 1/100 percent of efficiency is:

$$Rate\ of\ evaluation = (1{,}175.02\ \frac{\$}{kW}) \times (4.00\ \frac{kW}{1/100\%\ eff})$$
$$= 4{,}700\ \frac{\$}{1/100\%\ eff}$$

(3) *Application of rates of evaluation to contract bid and penalty for failure to meet guaranteed efficiency.* The calculated rate of evaluation per 1/100 percent of transformer efficiency shall be used during the bid evaluation to credit the bid price for each 1/100 percent of efficiency that the guaranteed value exceeds the specified minimum value of 99.63 percent. After final testing of the transformer, twice the rate of evaluation shall be applied as a penalty for each 1/100 percent of efficiency less than the guaranteed value.

(4) *Auxiliary cooling loss.*

(a) Guide Specification CE-2203 states the following:

> In the evaluation of Transformer Auxiliary Power, the power required for motor-driven fans and oil-circulating pumps should be evaluated on the basis that each horsepower of motor rating in excess of the number of horsepower excluded from evaluation is equal in value to approximately 40 percent of the capitalized value of one kW of loss used in the transformer efficiency evaluation.

(b) The rate of evaluation for transformer auxiliary power for FOA cooled transformers is given by:

$$Rate\ of\ evaluation = \$1{,}175 \times 40\% = \frac{\$470}{hp}$$

(c) The total horsepower of motor-driven fans and oil pumps excluded from evaluation for each size of transformer is given by:

Total losses based on 99.6% estimated efficiency:

$$\frac{46{,}000\ kVA}{99.6\%} - 46{,}000\ kVA = 184.74\ kW$$

Total auxiliary loss in *hp* excluded from evaluation:

$$184.74\ kW \times \frac{.05\ hp}{kW} = 9.24\ hp$$