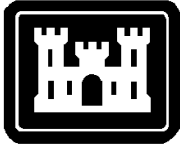


CECW-EP Engineer Manual 1110-2-3006	Department of the Army U.S. Army Corps of Engineers Washington, DC 20314-1000	EM 1110-2-3006 30 June 1994
	Engineering and Design HYDROELECTRIC POWER PLANTS ELECTRICAL DESIGN	
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EM 1110-2-3006
30 June 1994

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

EM 1110-2-3006

CECW-EP

Manual
No. 1110-2-3006

30 June 1994

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:

A handwritten signature in black ink, appearing to read 'William D. Brown', with a stylized flourish at the end.

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

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

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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 2-2b. 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 SF₆ 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.

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.

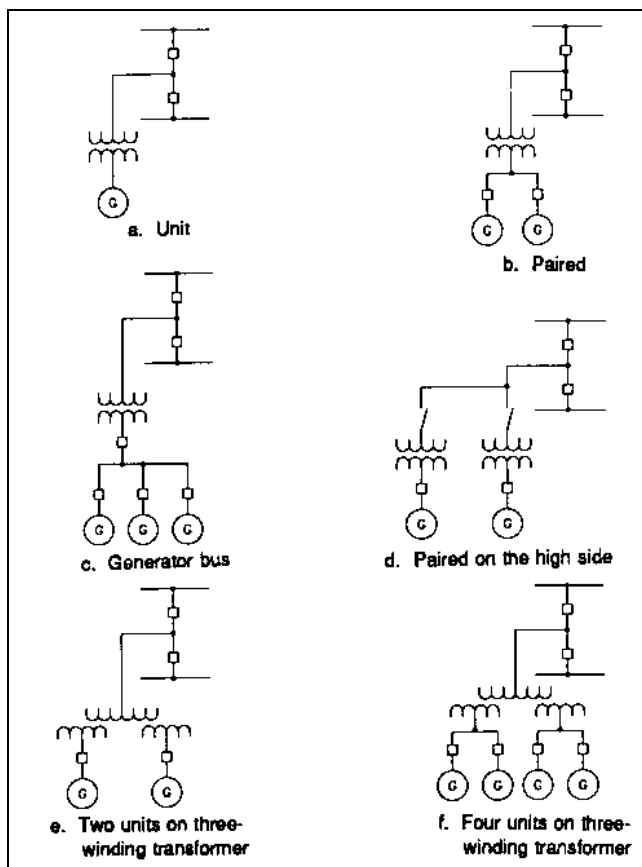


Figure 2-1. Main unit switching schemes

(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 2-1c 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 Sky-park 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-circuit 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_0), 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 water-wheel 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 3-2f).

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.

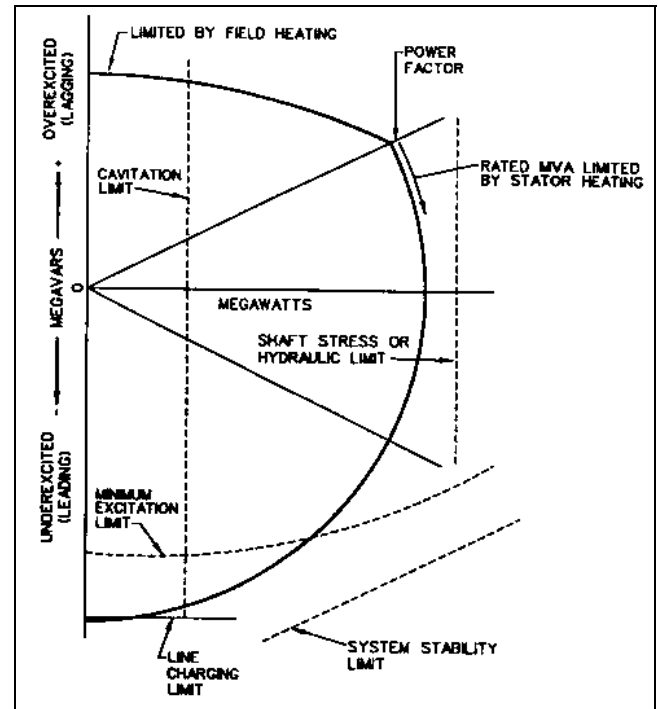


Figure 3-1. Typical hydro-generator capability curve

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				Price Addition (Percent of Basic Price)	Reduction in Full-Load Efficiency	Multiplier For Transient Reactance
	0.8PF	0.9PF	0.95PF	1.0PF			
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:

<u>Power Factor</u>	<u>Condenser Capacity</u>
.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

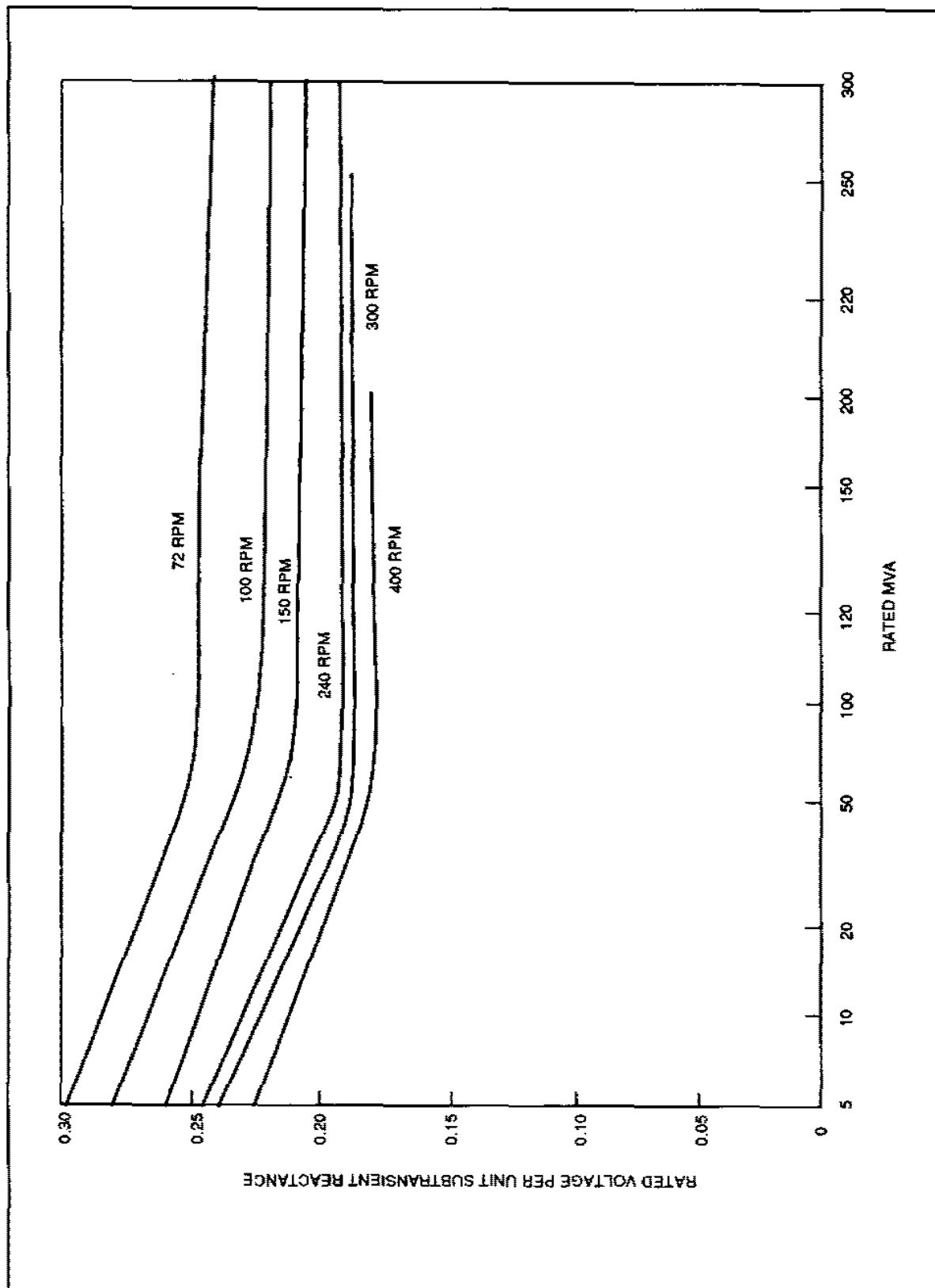


Figure 3-2. Typical generator transient reactances

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 inertia 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 3-2e).
- (2) Higher Wk^2 (see paragraph 3-5b).
- (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 8-6b(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 infrequency 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:

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

(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.

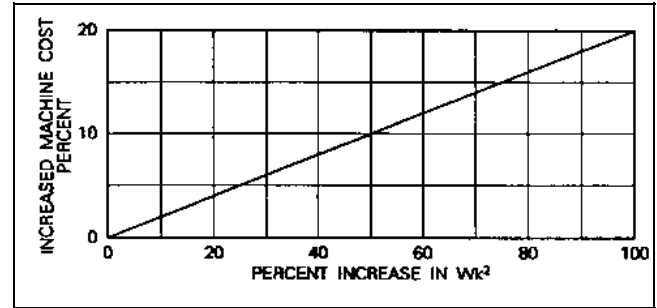


Figure 3-3. Effect of increased Wk^2 on generator cost (included by permission of Westinghouse Electric Corp)

(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 CO₂ 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 3-6g(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 windings 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 cooling 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		CLASS FOA OR CLASS FOW	
		MINIMUM	MAXIMUM	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 of impedance 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. Like-

wise, 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 4-6e, 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 4-6b).

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

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.

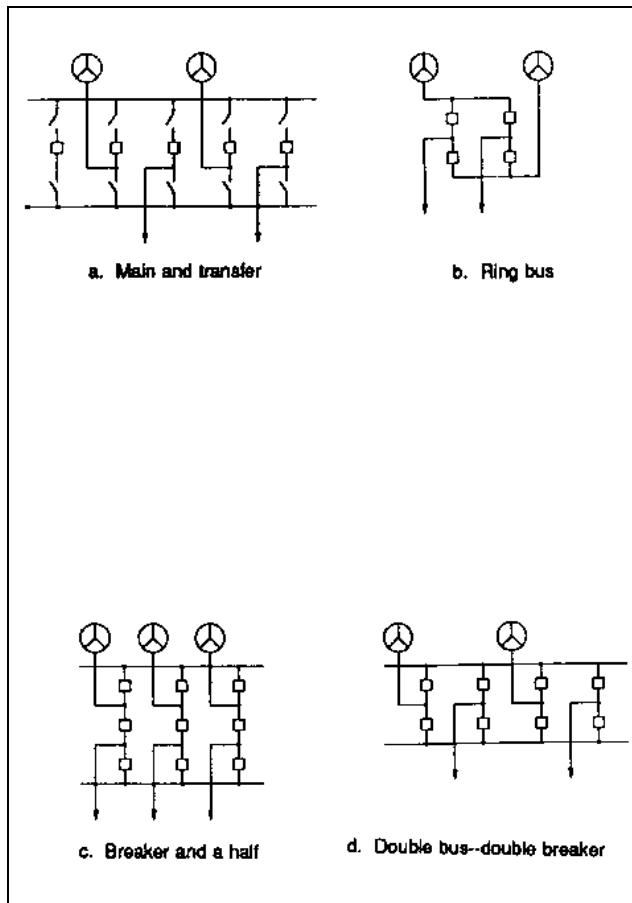


Figure 5-1. Switchyard bus arrangements

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 inter-connection 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 man-holes 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 SF₆ 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) SF₆ 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 accidentally penetrate the cable while digging in the burial area.

(4) SF₆ gas-insulated systems. SF₆ 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, SF₆ gas contains hazardous byproducts and special precautions are needed for evacuating the gas and making the equipment safe for normal maintenance work. SF₆ gas pressure varies with temperature and will condense at low ambient temperatures. When SF₆ 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 $-30\text{ }^{\circ}C$ (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_0 , 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_0 , 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 6-7b).

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 3-6e(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 SF₆ 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 SF₆ 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 SF₆ 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 SF₆ 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)	Inter- rupting Rating (kA)	Closing Mechanism
4.76	1.36	1.2	8.8	12	Stored Energy "
4.76	1.24	1.2, 2	29	36	
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)	Inter- rupting Rating (kA)	Closing Mechanism
15.8	1	<u>1/</u>	<u>2/</u>	<u>3/</u>	Stored
27.5	1	<u>1/</u>	<u>2/</u>	<u>3/</u>	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.