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CECW-EC

Engineering and Design
Mechanical and Electrical Design of Hydroelectric Power Plants

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FOR THE COMMANDER:

PRETTYMAN-
BECK.YVONNE.J.
1133246963

Digitally signed by
PRETTYMAN-
BECK.YVONNE.J.1133246963
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YVONNE J. PRETTYMAN-BECK
Chief of Staff

Purpose. The purpose of this engineer manual is to provide information and criteria pertinent to the design and selection of mechanical and electrical systems for hydroelectric powerplants.

Applicability. This manual applies to all Headquarters, United States Army Corps of Engineers elements, major subordinate commands, districts, laboratories, centers, and field operating activities having responsibilities for the design and construction of Civil Works projects.

Distribution Statement. Approved for public release; distribution is unlimited.

Proponent and Exception Authority. The proponent of this manual is the Civil Works Engineering and Construction Division (CECW-EC). The proponent has the authority to approve exceptions or waivers to this manual that are consistent with controlling law and regulations. Only the proponent of a publication or form may modify it by officially revising or rescinding it.

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*This manual supersedes EM 1110-2-3006, dated 30 June 1994 and EM 1110-2-4205, dated 30 June 1995.

SUMMARY of CHANGE

EM 1110-2-3006
Mechanical and Electrical Design of Hydroelectric Power Plants

This major revision, dated 02 APRIL 2024-

- Combines two manuals: EM 1110-2-3006 (30 June 1994), Hydroelectric Power Plants Electrical Design, and EM 1110-2-4205 (30 June 1995), Hydroelectric Powerplants Mechanical Design
- Updates and discusses current design philosophies and standards for hydroelectric powerplants.
- Updates references.
- Adds new chapters that address subject matters not previously covered:
    - Chapter 2 – Hydropower Plant Overview
    - Chapter 3 – Plant Rehabilitation Process and Considerations
    - Chapter 28 – Machine Condition Monitoring
    - Chapter 29 – Oil Spill Prevention
    - Chapter 30 – Arc Flash and Coordination
- Deletes the following content in the previous EM 1110-2-3006 (1994):
    - Chapter 16 – Procedure for Powerhouse Design
    - Chapter 17 – General Design Memorandum
    - Chapter 18 – Feature Design Memorandums and Drawings
    - Chapter 19 – Construction Specifications and Drawings
    - Chapter 20 – Analysis of Design
    - Appendix B – Power Transformer Studies and Calculations
- Deletes Appendix B from EM 1110-2-4205 (1995). Relevant content is redistributed into the appropriate chapters.

Contents (listed by chapter and page number)

Figure List

Chapter 1
Introduction, Scope, Codes, and Criteria

1–1. Purpose

The purpose of this engineer manual (EM) is to provide information and criteria pertinent to the design and selection of mechanical and electrical systems for hydroelectric powerplants.

1–2. Distribution Statement

Approved for public release; distribution is unlimited.

1–3. References

References, which include technical papers, engineering guidance, engineer manuals, industry standards, and textbooks are provided in Appendix A. References to industry standards concerning safety (such as the National Fire Protection Association [NFPA] series) are informational only and do not imply a means of legal enforcement or determination of liability through the use of this EM.

1–4. Records Management (Recordkeeping) Requirements

The records management requirement for all record numbers, associated forms, and reports required by this manual are addressed in the Records Retention Schedule – Army (RRS-A). Detailed information for all related record numbers is located in the Army Records Information Management System (ARIMS)/RRS-A at https://www.arims.army.mil. If any record numbers, forms, and reports are not current, addressed, and/or published correctly in ARIMS/RRS-A, see DA Pam 25-403 for guidance.

1–5. Associated Publications

a. Policy associated with the execution of work related to this manual is found in ER 10-1-53. It also defines the mandatory and optional engineering, design, and support services that will be performed by the Hydroelectric Design Center (HDC) for U.S. Army Corps of Engineers (USACE) hydroelectric powerplants.

b. Additional technical guidance and instruction associated with this manual is found in EM 1110-2-3001.

c. This manual should be used in conjunction with EM 1110-2-2610 and EM 110-2-1424 as well as all other referenced engineer manuals, technical letters, and engineering reports for the design, inspection, maintenance, and operation of hydroelectric powerplants.

d. Although EM 1110-2-2610 was written specifically for lock and dam operating equipment outside of the powerhouse, many parts of the manual overlap with the mechanical and electrical design for hydroelectric powerplants. This includes mechanical components such as couplings, gears, bearings, and hydraulic systems. EM 1110-2-2610 also provides discussion of electrical power systems, electrical controls, power distribution, lighting, and surge protection.

1–6. General

This document is a revision and update of the information presented in the 30 June 1994 version of EM 1110-2-3006 and the 30 June 1995 version of EM 1110-2-4205. These documents are now combined, and EM 1110-2-4205 is now obsolete.

a. *Hydroelectric Work*. For all covered work for hydroelectric plants, this manual governs in all cases of discrepancies, conflicts, or different approaches to similar equipment.

b. *Design Guidance*. This manual is not intended as a comprehensive step-by-step design manual to hydroelectric power plants and their systems. The designer is responsible for exercising sound engineering resourcefulness and judgment while using this manual. Used as a guide, it provides experience-oriented guidance and a basis for resolving differences of opinion among the competent engineers at all levels. Other material useful in hydroelectric powerplant design, which is readily available in standard publications, is referenced in Appendix A.

c. *Comments or Suggested Improvements.* Questions or comments regarding this manual and its contents should be directed to the HDC.

1–7. Mandatory Requirements and Deviation from Design Criteria

This manual provides guidance for the design of USACE hydroelectric powerplants and associated systems. In certain cases, guidance requirements, because of their criticality to project safety and performance, are mandatory as discussed in ER 1110-2-1150. Those cases are identified as “mandatory,” or the word “must” is used in place of “should.”

1–8. Safety Provisions

Certain safety provisions are required by EM 385-1-1 guide specifications, trade standards, codes, and other manuals referenced herein.

a. Additionally, the requirements of the Occupational Safety and Health Administration (generally referred to as OSHA standards) are to be considered minimum requirements in USACE design.

b. Areas of particular concern to mechanical and electrical design are safety, noise levels, personnel access provisions, working temperature conditions, air contamination, load handling provisions, fall hazards, confined space entry, and sanitary facilities. OSHA standards are continuously being modified and expanded. Conformance to the latest published requirements is essential.

Chapter 2
Hydropower Plant Overview

2–1. General

a. Hydropower plants are facilities that convert the potential energy of water into electricity. Some hydropower plants can also convert electricity into potential energy using pump turbines when operating in a pumping mode. Hydropower plants are often one aspect of a large complex that also consists of one or more of the following: dam, reservoir, spillway, navigation lock, fish passage facilities, and switchyards. The location of hydropower plants can vary but are most often located at or immediately adjacent to the dam.

b. The principal features of the hydropower plant include the powertrain equipment and balance of plant equipment. The powertrain primarily consists of the intake or penstock, turbine, generator, governor system, excitation system, electrical bus, breakers, and power transformers. The balance of plant equipment consists of numerous electrical systems, primary controls and indicators, electrical protection and metering, supervisory control and data acquisition, penstock shutoff valves, upstream and downstream gates and stoplogs, cranes and hoists, fire protection systems, oil and water plumbing systems, compressed air systems, unwatering and drainage systems, machine condition monitoring, communications, diesel generator sets, and other systems required to maintain the powerhouse.

c. Most hydropower plants include a powerhouse structure that may be integral with the dam (reference EM 1110-2-3001 and EM 1110-2-2200). The powerhouse foundation and superstructure contain the hydraulic turbine and water passageways. The other powertrain equipment, including the generator, governor system, excitation system, electrical bus, breakers, and switches, are typically located within the powerhouse structure, with the power transformers and switchyard located outdoors adjacent to the powerhouse. However, every powerhouse is unique and different designs have been constructed, including generators located outdoors. The balance of plant equipment is located primarily inside the powerhouse structure except where it is necessary to be located outside (such as an intake crane, switchyard).

d. Figure 2–1 shows a cross section of a hydropower plant with a focus on the powertrain equipment and wetted passageway.

e. Important references for details of hydropower work include Unified Facilities Guide Specifications (UFGS), Unified Facilities Codes, as well as USACE EMs. Several references from outside USACE also provide useful overviews and information about hydropower plants, such as the American Society of Mechanical Engineers (ASME) Hydro Power Technical Committee’s book “The Guide to Hydropower Mechanical Design” and the U.S. Bureau of Reclamation’s (USBR) Facilities Instructions, Standards, and Techniques (FIST) online manuals.

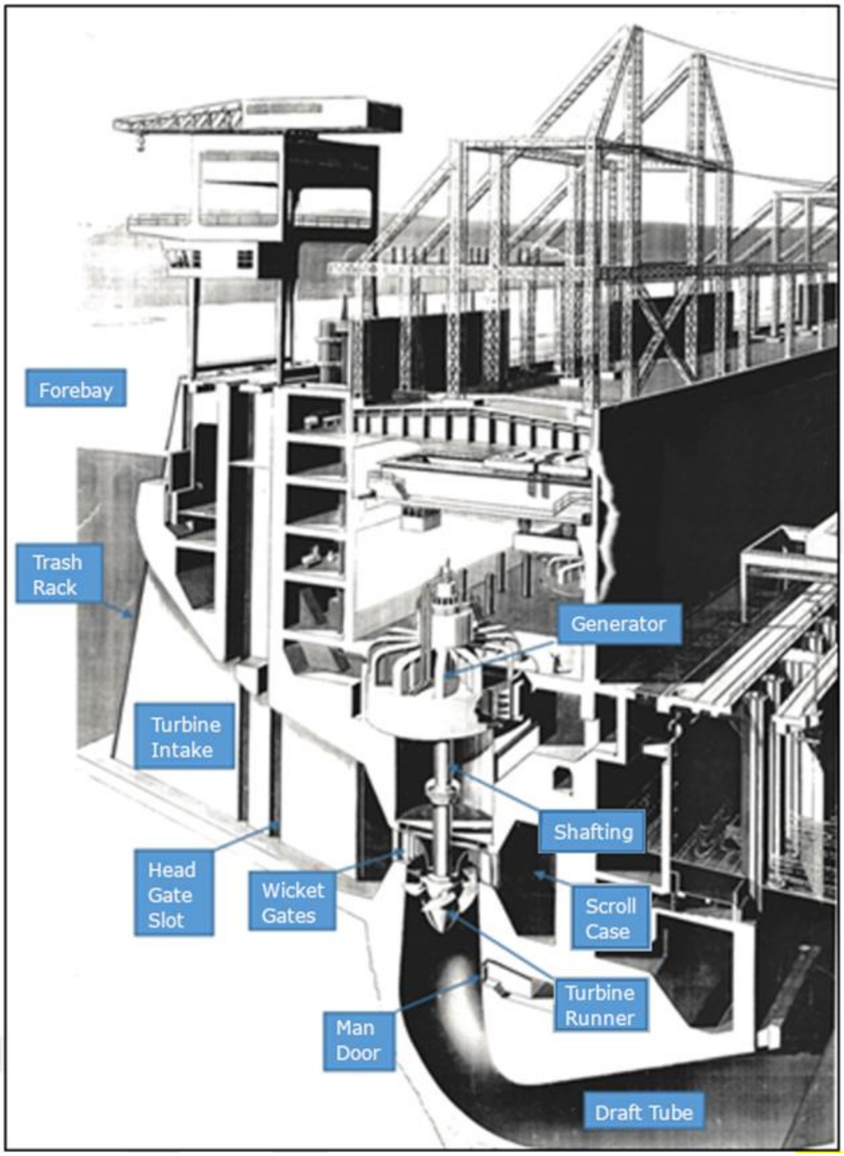


Figure 2–1. Cross section of a hydropower plant

2–2. Powertrain

The powertrain is a system that consists of the mechanical and electrical equipment directly involved in the generation and transmission of energy as part of the hydropower plant. The energy in a hydropower plant begins as potential energy stored in water and ends as electrical energy used by the power grid. In general, the energy is converted along the powertrain as follows:

a. Potential energy stored in water is converted to kinetic energy as it enters the intake or penstock. The hydraulic turbine converts the kinetic energy into mechanical energy. The mechanical energy is transmitted to the generator rotor via shafting.

b. The generator converts mechanical energy into electrical energy between the rotating field winding and stationary armature windings. The excitation system is used to provide field current to the field winding.

c. The electrical energy is transmitted from the generator to the power transformer through a configuration of bus and/or cabling, breakers, and/or switches. Figure 2-2 shows a simplified electrical one-line diagram.

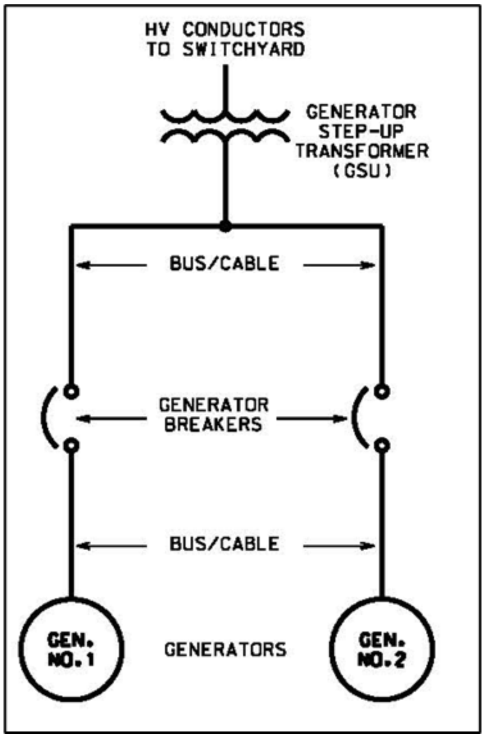


Figure 2-2. Simplified electrical one-line diagram

d. The power transformer increases the electrical voltage and lowers the current to reduce losses during transmission.

e. Conductors and other electrical equipment are then used to transmit the higher voltage electrical energy to a switchyard. The switchyard provides a reliable and flexible interface between the hydropower plant and the power grid.

2–3. Major Mechanical, Structural, and Electrical Powertrain Equipment

a. Components. While the powertrain consists of many components, the major mechanical, structural, and electrical systems include the intake or penstock, turbine, generator, governor system, excitation system, electrical bus, breakers, and power transformer. Additionally, a switchyard is part of the powertrain and provides the interface between the hydropower plant and the power grid. Each of these systems are discussed briefly as follows and in more detail in subsequent chapters.

b. Intake or Penstock. Water is conveyed to the turbine through an intake or penstock. An intake is an opening in the dam that conveys water from the reservoir to the turbine and is typically associated with propeller-type turbines, including fixed- and adjustable-blade vertical propellers, bulb propellers, and slant-axis propellers. A penstock is a pressure vessel or pipe that conveys water from the reservoir to the turbine, and is typically associated with Francis-type or impulse-type turbines. This manual does not cover intakes and penstocks; designers should reference EM 110-2-3001 for more information.

c. Turbine.

(1) The turbine includes all wetted components and equipment starting at the entrance to the scroll case or spiral case. It ends at the exit of the draft tube, including the scroll case or spiral case, stay ring/vanes, wicket gates, head cover(s), turbine runner, discharge ring, and draft tube liner and draft tube. A brief description of each component and piece of equipment is included below. These components and pieces of equipment may not be applicable across all turbine types but are included in the most common turbines associated with most head ranges.

(2) A brief discussion of pump, bulb, and tubular (low head applications), and impulse turbines (high head applications) is included to briefly describe variations associated with these types of turbines. Figure 2–3 and Figure 2–4 show section elevations of an adjustable-blade propeller and Francis turbine, respectively. See Chapter 5 for more details regarding turbines and pump turbines.

(a) Scroll Case or Spiral Case. The scroll case or spiral case distributes the water evenly around the circumference of the stay ring/vanes. Slant axis, bulb, and impulse turbines do not have a scroll case or spiral case.

(b) Stay Ring/Vanes. The primary purpose of the stay ring/vanes is to support the structural load above, but they also guide water flow into the wicket gates.

(c) Wicket Gates. The wicket gates regulate water flow through the turbine. The wicket gates consist of a series of gates that rotate to change the opening between the leading edge of one gate and the trailing edge of the adjacent gate. The wicket gates are operated through a series of linkages connected to an operating ring. The operating ring is connected to one or two servomotors, which are controlled by the governor system.

(d) Head Cover(s). Turbines include one or more head covers that separate the water from the turbine pit. The head cover or covers also support equipment located in the turbine pit.

(e) Turbine Runner. The turbine runner converts the kinetic energy of the water into mechanical energy and transmits the energy into the shafting system as torque. The two most common types of turbine runners are the propeller and Francis. Both types are reaction turbines. Propeller turbines are either axial flow or diagonal/mixed flow and can have blades in a fixed position or blades that change angle (adjustable blade, also sometimes referred to as “Kaplan”). Francis turbines are radial flow and have blades in a fixed position.

(f) Discharge Ring. The discharge ring forms the stationary portion of the turbine that surrounds the turbine runner of a propellor turbine and contains the water.

(g) Draft Tube Liner and Draft Tube. The draft tube liner is a transition between the discharge ring and draft tube. The draft tube recovers the kinetic energy from the outlet of the turbine runner and conveys the water to the tailrace. This manual does not cover draft tubes; designers should reference EM 1110-2-3001 for more information.

(h) Other Turbine Equipment. Numerous other pieces of equipment are typically associated with the turbine. In general, equipment located in the turbine pit is associated with the turbine. Examples include the packing box, wicket gate linkages, operating ring, wicket gate servomotors, vacuum breakers, and turbine guide bearing.

Additionally, a turbine shaft and sometimes an intermediate shaft and/or a blade servomotor shaft are supplied by the turbine manufacturer.

(i) *Pump Turbine*. In some cases, the turbine runner is designed in such a way as to allow pumping operation. The generator operates as a motor and the conversion of energy is the opposite from a hydroelectric generating unit, starting with electricity converted to mechanical energy, then to kinetic energy of the water, and finally into potential energy with water being moved into an upper reservoir or forebay.

(j) *Bulb and Tubular Turbines*. To reduce excavation costs, some hydropower plants with low head have turbines with horizontal or inclined shafts. A common horizontal shaft configuration is to house the generator upstream of the runner in a submarine-like structure. These are called bulb turbines. A variation on this design is to house the upstream generator in a concrete silo with the water passages on either side. This is called a pit turbine. Rather than the generator being upstream, the shaft may extend downstream, either horizontally or inclined at an upward angle. In these configurations, the shaft can extend through the draft tube liner so that the generator is not housed inside the water passages. Whether the shaft is horizontal or inclined, these are referred to as tubular turbines. Tubular turbines with an inclined shaft are sometimes referred to as slant-axis turbines.

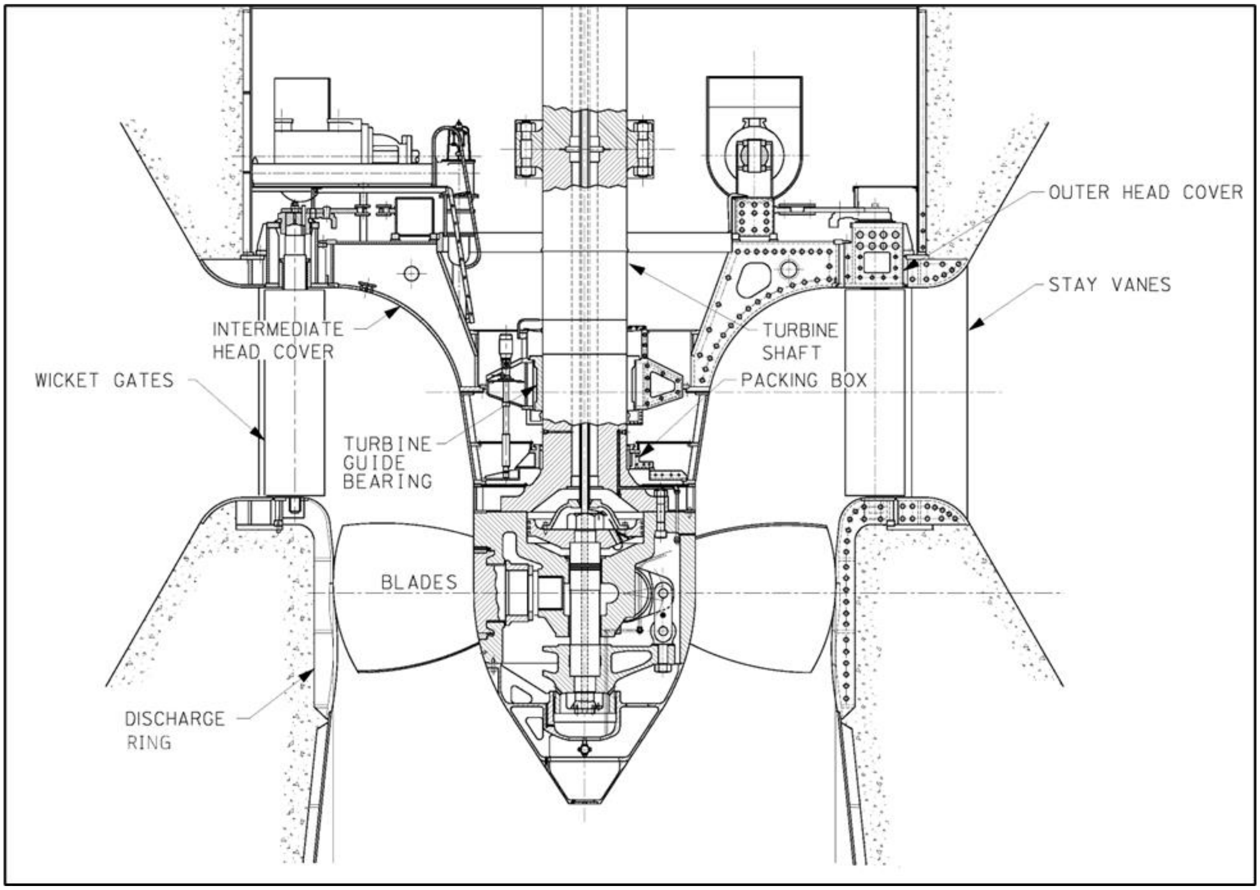


Figure 2–3. Sectional elevation of an adjustable-blade propeller turbine

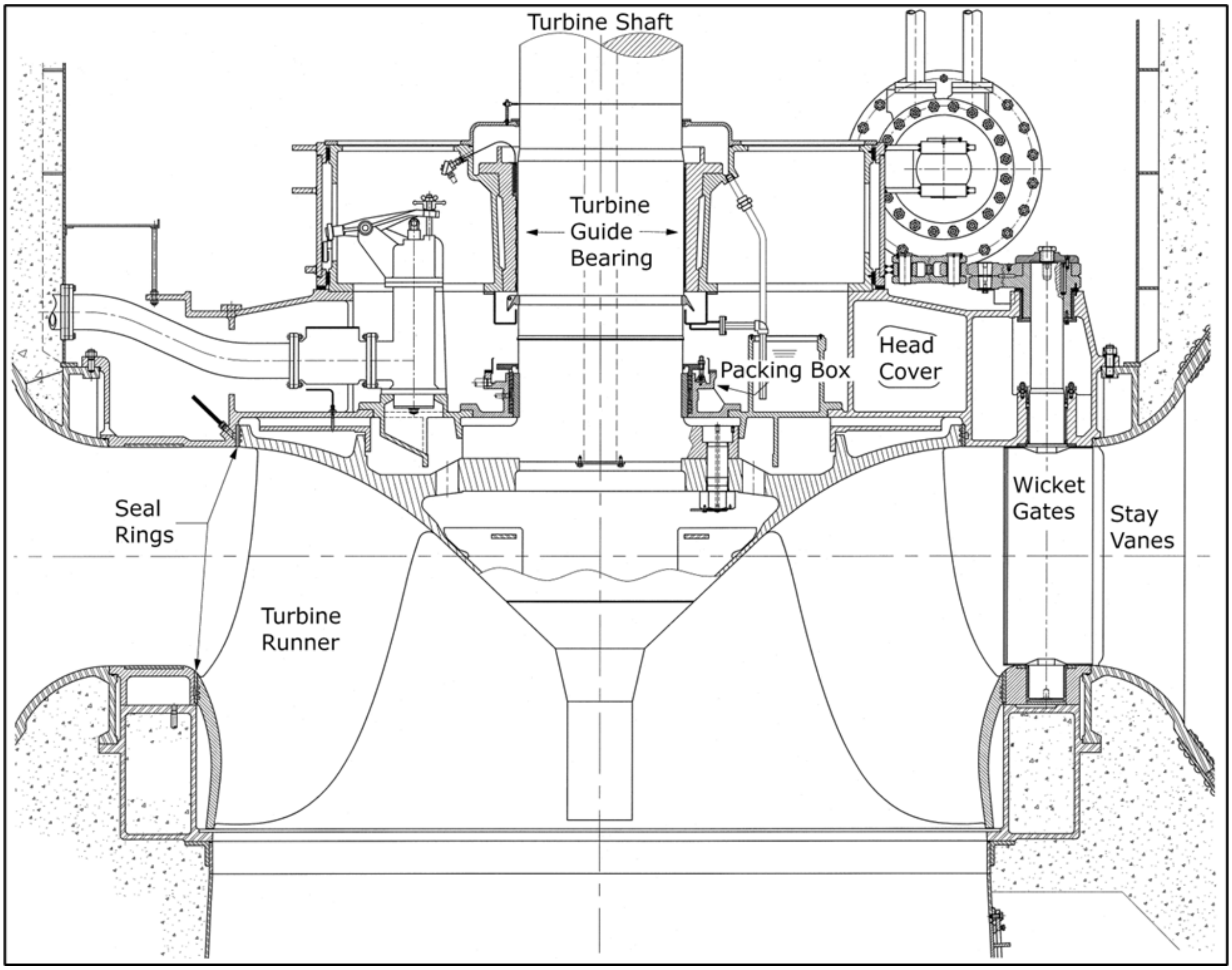


Figure 2–4. Sectional elevation of a Francis turbine

(k) Impulse Turbine. For higher head applications, the preferred choice is an impulse turbine. There are many impulse turbine designs, but the most common is a Pelton. In a Pelton turbine, water jets discharge directly from a nozzle, or multiple nozzles, into buckets mounted around the periphery of the runner. The water jet causes the runner to rotate and then falls out of the bucket into the tailwater. Instead of wicket gates, the flow is controlled with a needle valve at each nozzle.

d. Generators and Motor-Generators.

(1) The generator or motor-generator primarily consists of a stator, rotor, generator shaft, generator coolers, brakes and jacks, guide bearings, and thrust bearing. A brief description of each component is included below.

(2) The hydraulic turbine-driven generators used in USACE powerhouses are synchronous alternating-current machines, which produce electrical energy by transforming potential energy. The electrical and mechanical design of each generator must conform to the electrical requirements of the power distribution system and the hydraulic requirements of its specific plant. In the case of pumped-storage hydropower plants, a generator may also serve as the pump motor. Figure 2–5 shows an example

sectional elevation of a generator. See Chapter 6 for more details regarding generators and motor-generators.

(a) Generator Stator. The generator stator consists of a stator foundation, stator frame, stator core, and stator windings, among other components. Stator foundations are designed to transmit gravity loads to the powerhouse structure, to dampen vibration, to allow the stator to accommodate normal radial forces while resisting translation, and to allow the generator to withstand "generator upset" conditions with minimal damage. The primary component of the stator core is the thin sheet-steel laminations that, when stacked together and clamped, form the stator core. The stamping shapes are designed and assembled to form stator winding coil slots. Within the slots of the stator core, the stator coils or bars are installed, along with a variety of other materials that serve the primary purposes of tightly packing the winding in the slots and to ensure integrity of the external semiconductive coating of the bar.

(b) Generator Rotor. The generator rotor is the main rotating assembly of the generator and is driven by the hydraulic turbine via shafting. The rotor is composed of the hub, arms, rim, pole pieces, and field winding. The hub provides a connection to the rotor from the shafting system. The arms connect the hub to the rim. The rim forms the outer diameter surface that provides a mounting location for the rotor pole pieces. Pole pieces, which support the field winding, are attached to the rim with a wedge key system. The field winding is generally made up of copper conductors that are "wrapped" in some fashion around the pole pieces.

(c) Generator Shafts. Shafting transmits power from the hydraulic turbine to the generator rotor. The portion of this shafting to which the generator rotor is attached is the generator shaft. In turn, this shafting is connected to the turbine shaft, which connects to the turbine runner hub. 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.

(d) Generator Coolers. Losses in a generator appear mainly as heat, which is dissipated through radiation and ventilation. The generator rotor is normally constructed to function as an axial flow blower, or may be 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 fully enclosed in an air housing with air/water heat exchangers to remove heat losses.

(e) Generator Brakes and Jacks. Generators are equipped with brakes to slow and stop the rotation of the unit. Some units are equipped with combination brake/jacks that can also be used to lift the unit off the thrust bearing for maintenance. The brake/jack assemblies are mounted below the generator, typically on the lower bearing bracket. The brake pads bear on a ring that is bolted to the bottom of the generator.

(f) Generator Guide Bearings. Generator guide bearings support the unit in the horizontal plane. All units will have at least one guide bearing. 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 generator guide bearing is required. The lower generator guide bearing is often referred to as the "lower guide bearing," even though the turbine guide bearing is the lowest one.

(g) Thrust Bearing. The thrust bearing consists of a rotating ring (sometimes referred to as a "thrust runner") and multiple stationary segments (sometimes referred to as "shoes"). The thrust bearing transfers the axial load of the rotating components from the hydroelectric generating unit to the static, structural components. The thrust bearing may be located above or located below the generator rotor. Figure 2–5 shows the bearing above the generator rotor.

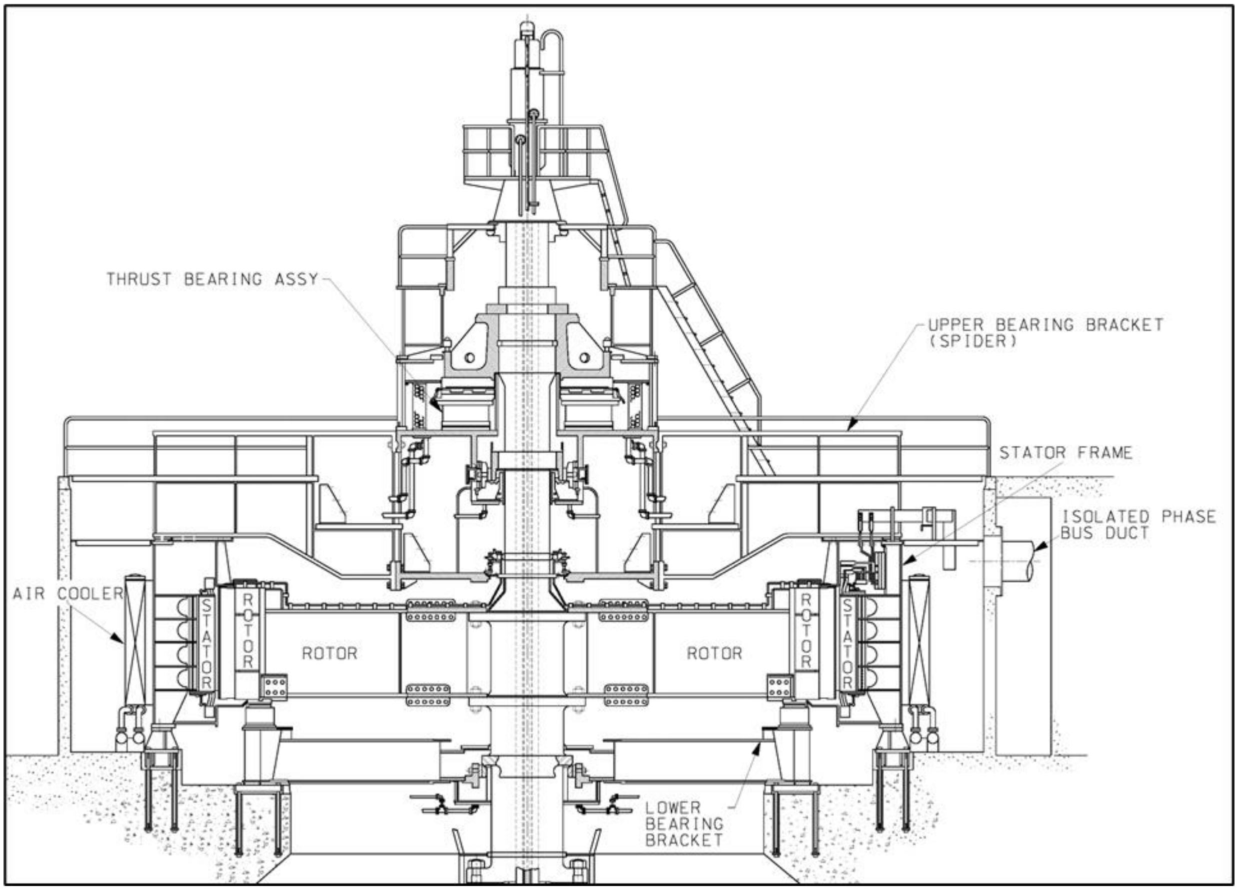


Figure 2–5. Sectional elevation of a generator

e. Excitation Systems. Excitation systems provide current to the field element of the generator rotor. The resulting rotating magnetic field induces current in the generator stator windings. There are three types of excitation systems used in hydroelectric power generation: static, rotating, and brushless rotating. Figure 2–6 shows a system schematic of a static-type excitation system. See Chapter 8 for more details regarding excitation systems.

f. Generator Bus, Neutral Grounding, Surge Protection, Instrument Transformers, Power Potential Transformers. The primary purpose of the generator bus is to carry electrical current between the generator and transformer. This equipment is functionally located between the generator terminals and the low-voltage terminals of the generator step-up (GSU) transformers, and between the neutral leads of the generator and the power plant grounding system (see Figure 2–7). See Chapter 9 for more details regarding generator bus, neutral grounding, surge protection, instrument transformers, and power potential transformers (PPTs).

(1) *Generator Leads*. 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 on the distance between the generator and transformer, the capacity of the generator, the type of generator breakers employed, physical limitations, and the economics of the installation.

(2) *Neutral Grounding Equipment*. All main unit generators at USACE powerhouses generate in a wye configuration, providing a neutral point that must be grounded. The neutral grounding conductor may be either metal-enclosed bus or insulated cable in conduit. Solid neutral grounding is not feasible on main unit generators due to very high ground fault currents that could be several times higher than available three-phase fault current. All grounding should be done through a circuit breaker or disconnect switch to allow isolation for maintenance purposes.

(3) *Generator Surge Protection*. Voltage surges occurring on the generator bus can be caused by lightning strikes on the transmission line or by switching transients, particularly by the operation of the generator breaker.

(a) Surge Arresters. When the overvoltage reaches the design limit of the connected surge arrester, the current gets shunted to ground, thus alleviating the voltage surge. See Chapter 9 for additional information on surge arresters.

(b) Surge Capacitors. Surge capacitors are almost always used in parallel connection with surge arresters for large synchronous generators because of the effect the system reactance has on transient voltages (see Figure 2–8). Although metal oxide surge arresters adequately limit the magnitude of surge overvoltage, they are not so effective in controlling the voltage rate of rise. Surge capacitors are designed with low internal inductance to limit the rate of rise of the surge overvoltage by reducing the steepness of the wave front, and thus better protect turn-to-turn insulation.

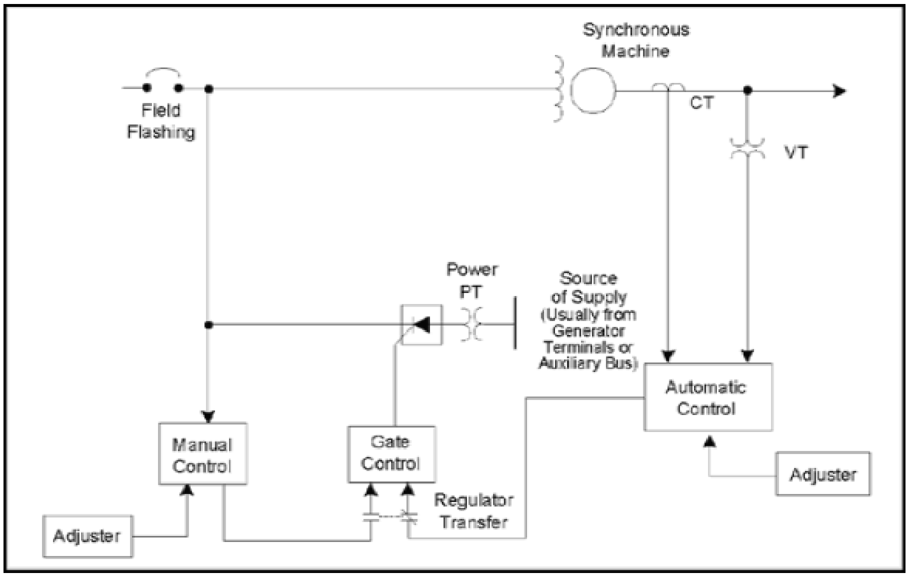
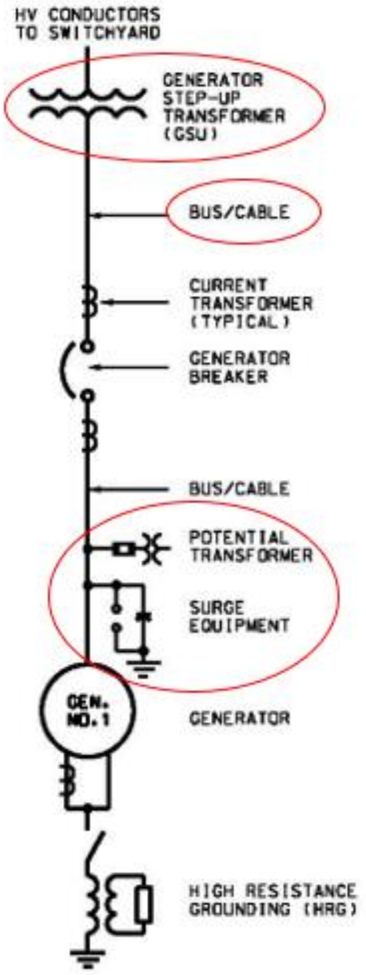


Figure 2–6. Static excitation system schematic (IEEE 421.1, 2007)



Isophase bus connection to GSU

Isophase bus leaving generator with tap to surge equipment and PT drawers

MV cables

Isophase bus

Figure 2–7. Assorted equipment for generator bus

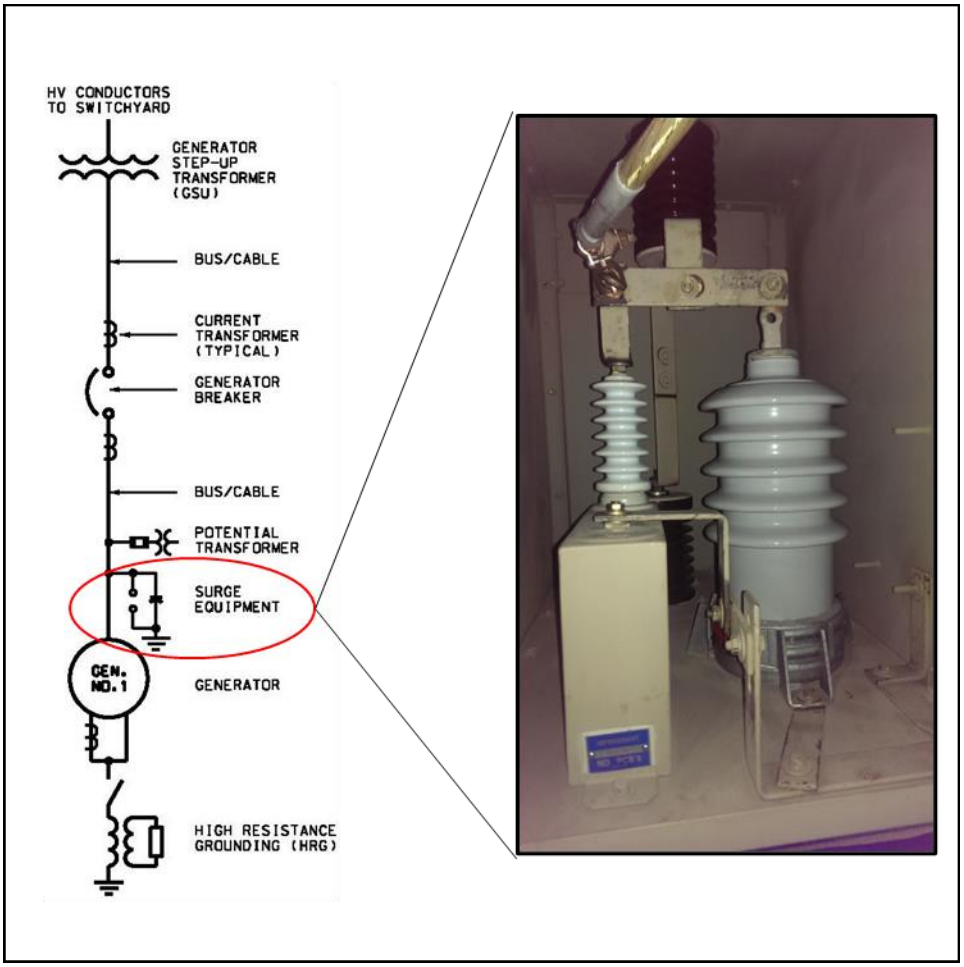


Figure 2–8. Surge capacitor (left) and arrester (right)

(4) *Power Potential Transformers*. PPTs for main unit exciters are typically powered by taps to the generator bus and mounted in a separate enclosure (see Figure 2–9). Large installations using isolated-phase bus may use an isolated-phase bus tap directly to the enclosure outside of the generator barrel. Installations not using isolated-phase bus often use cable in conduit, tapping the generator bus within the generator barrel and extending to the PPT enclosure.

(5) *Instrument Transformers*. Instrument transformers are used for metering the generator output and for generator protective relaying. Relays and meters typically cannot directly measure the utilization voltage and current of main unit generators. Instrument transformers, which include potential (voltage) transformers and current transformers, measure these utilization values and typically provide an equivalent of 120 volts alternating current (AC) and 5 amps maximum for use by the relays and meters.

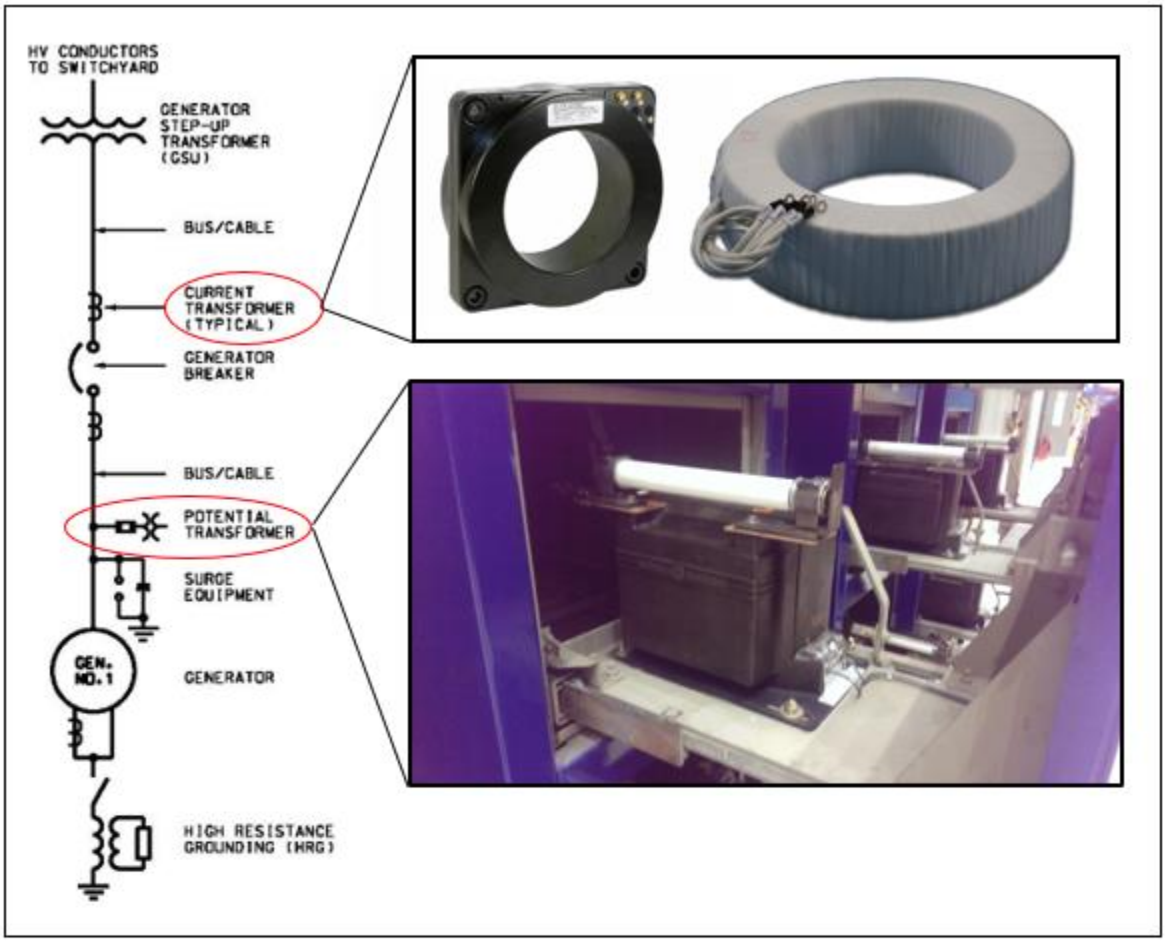


Figure 2–9. Potential transformers

g. Generator Breakers. Generator circuit breakers are placed in the generator bus between the generator terminals and the GSU transformer (see Figure 2–10). The breaker is used to interrupt the circuit between the generator and GSU transformer under normal operating conditions and during fault conditions. The generator voltage and capacity rating, and the results from fault studies determine the type of generator breaker used, together with its continuous current rating and short-circuit current rating. See Chapter 10 for more details regarding generator breakers.

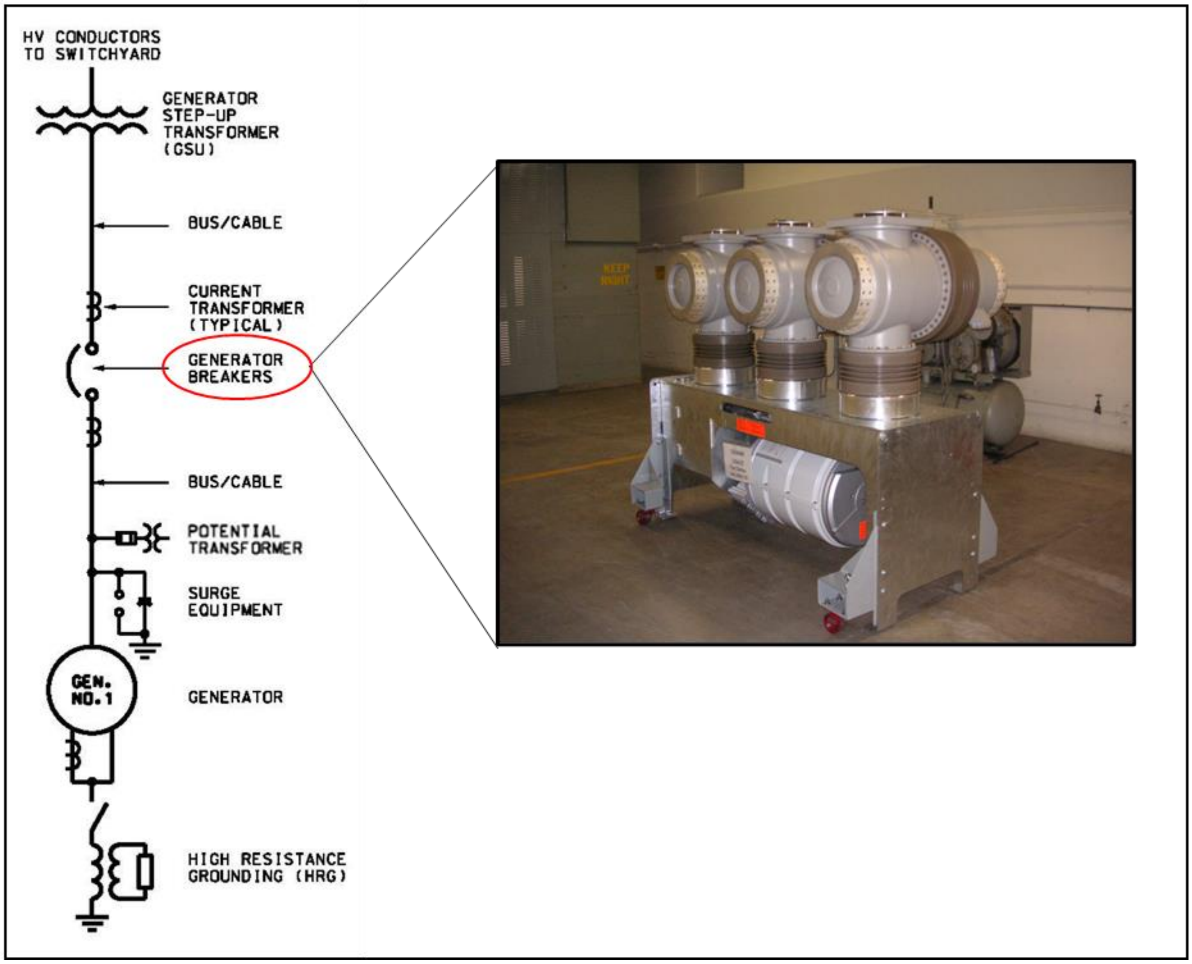


Figure 2–10. Generator breakers (interrupter shown outside enclosure)

h. Power Transformers. These transformers step up the voltage output of the generators to that of the power transmission system to which the hydropower plant is connected (see Figure 2–11). Step-up transformers for use with generating units should be of the oil-immersed type for outdoor operation, with a cooling system suited to the location. For most applications, three-phase transformers are used for GSU applications. See Chapter 11 for more details regarding power transformers.

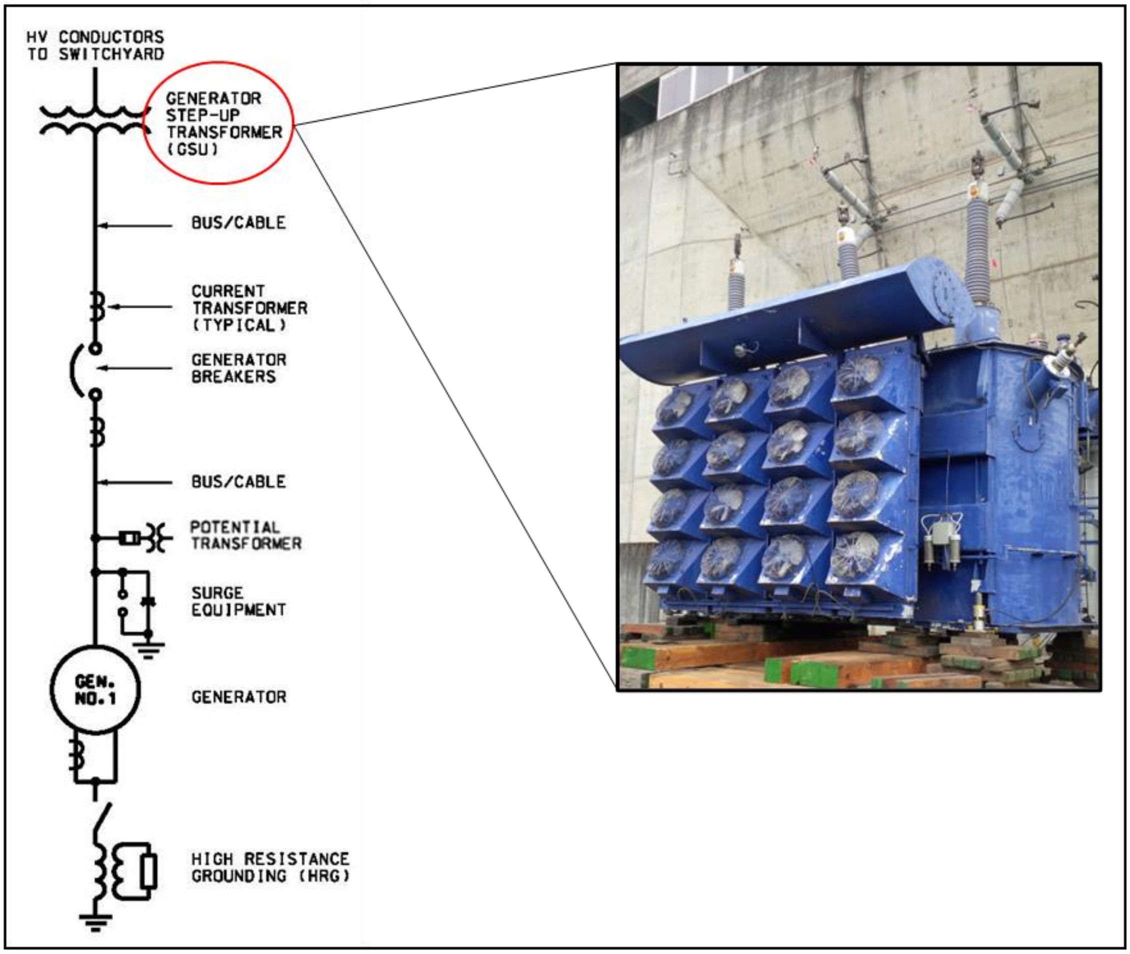


Figure 2–11. Generator step-up transformer

2–4. Balance of Plant Equipment

a. In addition to the major equipment discussed so far, there is a variety of other equipment in any powerhouse.

b. Some balance-of-plant equipment is critical to the successful maintenance of the powertrain equipment. This equipment includes, but is not limited to:

(1) Permanently installed cranes and hoists (see Chapter 20).

(2) Intake gates and draft tube bulkheads (not covered by this manual).

(3) Powerhouse drainage systems and unwatering systems (see Chapter 27).

(4) Emergency closure systems (see Chapter 20).

(5) Turbine maintenance platforms (not covered by this manual).

(6) Raw water (cooling) systems (see Chapter 24).

(7) Major equipment laydown areas such as a rotor pedestal (see Chapter 6).

(8) Diesel generator sets (see Chapter 15).

c. Some balance-of-plant equipment is required for safety or environmental reasons, such as:

(1) Fire protection systems (see Chapter 21).

(2) Oil-water separators and oil containment (see Chapter 29).

(3) Plant-wide annunciation systems (see Chapter 16).

(4) Seismic restraints (not covered by this manual).

d. Other balance-of-plant equipment can be less critical to the generation of power or powertrain, but is still important to the operation and maintenance (O&M) of the plant. Depending on the size of the units and the nature and location of the plant, these systems can include:

(1) Heating, ventilating, and air conditioning systems (see Chapter 36).

(2) Station service (see Chapter 15).

(3) On-site oil purification systems (see Chapter 23).

(4) Potable water systems (see Chapter 24).

e. General familiarity with balance-of-plant equipment and how it supports and interfaces with major equipment is a benefit to any hydropower engineer and can help prevent unforeseen delays in the execution of critical contract work.

Chapter 3
Hydropower Plant Rehabilitation Process and Considerations

3–1. General

a. Most hydropower engineering work currently is done in the context of rehabilitation rather than new construction. This edition of the EM includes updated information about constraints and considerations in terms of rehabilitation work. Major rehabilitations can address all powertrain equipment from "water-to-wire," as well as ancillary systems in the powerhouse that support the powertrain (balance-of-plant equipment). Updates specific to certain equipment is included in the chapter for that equipment. This chapter gives an overview of the rehabilitation process from a plant-wide, programmatic and systems viewpoint. The goal for a programmatic approach is to coordinate current and future work to maximize the benefits of each rehabilitated component, resulting in a comprehensively rehabilitated powerhouse.

b. Further guidance on this subject, including project management details, is available from HDC for USACE use.

c. There are also useful references from outside USACE, such as Institute of Electrical and Electronics Engineers (IEEE) Standard 1147 and Centre for Energy Advancement through Technological Innovation (CEATI) T083700-0355.

d. Plant rehabilitations are often part of regional/master planning documents to coordinate the rehabilitation of multiple plants across an area, or rehabilitation of similar systems across many plants.

3–2. Hydropower Plant Rehabilitation Drivers

a. *Outages*. A desire to reduce the number and duration of forced outages can motivate the decision to perform a major rehabilitation, with the goal of increased reliability and reduced maintenance costs.

b. *Power Output*. A desire to increase unit power output can motivate a rehabilitation. In some cases, aging units are operated at reduced capacity due to their condition, and a rehabilitation allows them to be operated at full capacity. In other cases, modern designs and materials can allow a new unit to have a higher capacity than the existing unit was designed to achieve.

c. *Unit Design*. A desire to significantly change a unit design can motivate a rehabilitation. Changes in hydraulic operating conditions (head and flow) can impact machine operation and output. New designs can also support environmental considerations, incorporating improvements in fish passage or improved oxygen content in the water.

d. *Plant Rehabilitation Approach*. Generally, the approach for developing an overall rehabilitation program can be divided into two major elements of work.

(1) *Part 1 – Studies and Assessments*. Equipment sizing studies and/or assessments are performed for the major powertrain equipment, and system assessments are performed for the balance-of-plant equipment. These can be performed sequentially or concurrently and are required to quantify the scope of work for the rehabilitation program.

(2) *Part 2 – Plan Formulation*. This includes (a) determining items to be included in the rehabilitation program based on the results of the studies and assessments, (b)

developing engineering estimates for the base rehabilitation program and incremental cost for any identified incremental benefits, and (c) formulating a plan that organizes the scope of the rehabilitation program into distinct contract actions or work to be done by project staff. This phase also includes developing a comprehensive program schedule for preparing pre-design documentation, preparing plans and specifications, the acquisition phase, and the on-site construction phase for each of the contracts in the program.

3–3. Part 1 – Rehabilitation Studies and Assessments

a. *General*. Studies and assessments are required to determine which equipment and systems need to be rehabilitated or replaced. Results from these studies and assessments may also help in identifying how soon the rehabilitation or replacement needs to occur. The lists of equipment to be evaluated are extensive, but these studies and assessments are the foundation of the rehabilitation decision process. Planning and management staff must be thoroughly familiar with the magnitude of this effort to understand the scope and detail of the planning work that must occur. While there is always flexibility in sequencing the work, the studies and assessments should be completed prior to proceeding with Part 2, Plan Formulation.

b. *Studies*. One of the first activities in a planned powerhouse rehabilitation program is performing studies to determine the desired turbine operating characteristics (such as higher output, aeration, improved fish passage). If the studies include the possibility of the electrical powertrain equipment (such as a generator, transformer, bus, switchgear), then there is a need to investigate how these components must be rehabilitated, uprated, or replaced to support the increased turbine output. Three studies are typically required to address all the equipment within the powertrain: a turbine operating characteristics and power study, a generator uprate study, and an electrical powertrain sizing study. These studies should be coordinated as necessary to determine the overall most cost-effective level of upgrades for the rehabilitation.

(1) *Turbine Operating Characteristics and Power Study*.

(a) This study should be performed even if no increase in power output is being pursued. Regardless of initial motivation, once the decision is made to rehabilitate a turbine, all possible benefits of rehabilitating the unit should be considered.

(b) This study assesses the physical condition of the existing turbine and the appropriate power output and performance characteristics of the rehabilitated turbine, and whether an increase in turbine power output is justified. In locations where an absolute benefit above baseline is needed, a performance test may need to be completed. Substantial input from the district and other stakeholders, such as the applicable power marketing administration, is needed to define the needs for the rehabilitated turbine to fulfill. Project hydrology and constraints, head variations, peak versus base-load operations, and grid stability are among the many factors to consider.

(2) *Generator Uprate Study*. This study includes a complete mechanical, electrical, and thermal evaluation of all generator components, as well as a condition assessment. This analysis identifies the maximum continuous generator rating possible with the existing components, and what higher levels of output might be possible with refurbishment or replacement of components. Gathering documentation can take a significant effort. Required information includes generator design drawings,

commissioning test records, O&M manuals, operating records, failure reports, repair reports, and potentially component dimension field verification. If no increase in power output is being considered, then a condition assessment of the generator components is needed instead of the uprate study.

(3) *Electric Powertrain Study*.

(a) This study evaluates the condition and electrical capacity of the equipment from the terminals of the generator up to and including the main unit transformer and any high-voltage equipment. A full transformer load fault study is not typically required but consider a review of the fault current available and the equipment ratings. The powertrain study identifies improvements that are required to handle the maximum power output from the unit. This study requires several inputs, including the maximum megavolt-amperes (MVA) the generator will be capable of producing, the nameplate ratings of existing equipment in the electrical powertrain, the sizes and types of medium- and high-voltage conductors, and if applicable, the size of the switchyard bus and aerial lines that will need to carry the increased load.

(b) If no increase in power output is being considered, and no concerns exist over impaired ratings or problems with existing components that might have been overlooked, then a condition assessment of all the electric powertrain components downstream of the generator is needed instead of the powertrain study.

c. *Assessments*. Either concurrent with or after the completion of the studies identified above, the condition of various systems within the plant should be assessed to determine whether they should be included in the scope of the rehabilitation program. Assessments should include equipment and facilities required to execute the major rehabilitation work (such as bridge cranes). Condition assessment data such as from the Project's facility equipment maintenance program and hydroAMP scores should be used as part of these assessments where available. These assessments determine the appropriate scope for the major rehabilitation; they are not necessary for equipment that is already either definitively in scope or definitively out of scope. Lists of equipment and systems that should be considered for assessment are:

(1) *Turbine*. Turbine runner, turbine shaft (including collars and couplings), guide and thrust bearings, wicket gates (including bushings and alignment), operating ring, servomotors, vacuum breakers, and miscellaneous turbine components.

(2) *Structural Systems*. Powerhouse stability and integrity, major equipment laydown, major equipment foundations, hydraulic steel structures (HSS), gates and bulkheads, turbine maintenance platforms, seismic restraint, transformer oil containment.

(3) *Mechanical Systems*. Cranes, lifting beams and lifting devices, intake emergency closure, fire protection systems, tailwater depression system, scroll-case fill valves, unwatering system, drainage system, generator rotor spider, generator brakes, lube oil system, governor oil system, transformer oil system, oil-water separator, oil spill prevention systems, station air system, governor air system, raw water system, potable water system, speed-increasing gear drives, and heating, ventilation, and air conditioning (HVAC).

(4) *Electrical Systems*. Generator, excitation system, governor system, generator bus, main unit breakers, main unit transformers, switchyard, unit auxiliary motor control centers (MCCs), direct current (DC) and essential AC systems, emergency backup

power supply, protective relaying, annunciation system, power plant control system, cables and raceways, control boards.

d. *Items of Particular Interest*. There are some pieces of equipment or systems that can cause significant delay and disruption to program execution when not addressed early in the major rehabilitation program.

(1) *Hydropower Load-Handling Equipment*. Functional powerhouse cranes, intake and tailrace cranes or hoists, and below-the-hook (BTH) lifting devices are critical to successfully executing a rehabilitation program. Any needed rehabilitation, upgrades, testing, and acceptance (or if applicable, engineered lift plans) should be completed before starting site work on the turbine and generator. The long lead times required for work on load-handling equipment should be considered early in a rehabilitation program.

(2) *Headgates, Bulkheads, and Stoplogs*. Inspections of HSS such as turbine headgates, intake bulkheads, and draft tube stoplogs should be up to date before starting site work. Additional sets of gates and bulkheads may be needed to support normal ongoing maintenance, long-term turbine rehabilitation, and any breakdowns or unanticipated events. The possibility of unforeseen rehabilitation delays requiring the unwatering of a second unit prior to watering up the first unit should be considered. The condition of gates and bulkheads in terms of protective coatings and appurtenances should be assessed in context of the length of continuous submerged service supporting the major rehabilitation.

(3) *Updated Electrical Drawings*. Up-to-date electrical drawings are necessary for any contract involving unit controls, unit protection systems, or the supply of station service power throughout the facility. The time needed to complete the task of surveying the existing wiring system, then creating drawings that correctly describe the wiring system should be accounted for in developing the rehabilitation program.

3–4. Part 2 – Plan Formulation

a. *General*. Primary activities in plan formulation include the following activities:

(1) Deciding which work is to be performed,

(2) Estimating costs of the work,

(3) Organizing the work items in the scope into distinct contract actions or in-house efforts, and

(4) Developing an overall program schedule.

b. *Planning*. Usually, these activities are not sequential. Powerhouse rehabilitation planning involves considering multiple options and combinations of scope, costs, and acquisition methods. Developing a rehabilitation plan for the multiple systems involved is an iterative process. During the span of years involved in planning and completing individual acquisitions, the details of the overarching plan should be revisited and adjusted. Continuing equipment deterioration or failure as well as budget constraints may dictate adjustments to the plan.

c. *Scope*. Based on the studies and assessments, the scope of the equipment and systems to be included in the rehabilitation program can be developed. At this point, the program needs to be broken down into smaller, manageable projects. Decisions are needed as to which items in the scope are to be contracted out and that can be performed using Project labor. Rehabilitation items also need to be organized to ensure critical equipment and systems are in place before it becomes time for the unit outage. Considerations when establishing the scope of work include:

(1) Results from studies and assessments.

(2) Condition of existing equipment.

(3) Ability of Project staff and cost to maintain the exiting equipment in working condition.

(4) Risk of forced outages.

(5) Cost of repair, rehabilitation, or replacement.

(6) Available funding.

(7) Prioritizing among the competing needs so the most critical items are addressed first.

d. Organizing Work Items. For the line items that require equipment and services to be obtained by contract, the scope of each contract should be based on a logical consolidation of the rehabilitation items and on a strategically planned sequence of work. Some rehabilitation items may need to be stand-alone items, with their own project delivery teams, to be completed prior to taking a unit out of service for rehabilitation.

(1) Examples of stand-alone contracts might include intake, tailrace, and powerhouse crane rehabilitation contracts; new and/or refurbished gates and bulkheads; turbine maintenance platform to support turbine disassembly; supply contract for the GSU transformers; lead abatement or asbestos removal contract for the generators; service contract for updating electrical drawings.

(2) Examples of consolidated contracts might include a main rehabilitation contract that includes the turbine, generator, and excitation systems; electrical balance-of-plant contracts could include main unit breakers, switchgear, bus work, transformer installation, and station service distribution.

(3) Some of the rehabilitation items may be accomplished with in-house staff following designs provided or reviewed by the HDC (such as replacement of protective relays, annunciation systems).

e. Program Schedule.

(1) *Overview.* From the list of contracts and in-house efforts identified above, an overall program schedule should be developed to determine a logical progression of activities to successfully execute the work. For each contract or in-house effort, the major work activities for both the design phase and execution phase needs to be identified. For each activity, the task duration, predecessor tasks, and successor tasks need to be identified. Not only do task relationships within a contract need to be identified, but also task and activity relationships among the various contracts. For example, the bridge crane rehabilitation, including BTH lifting devices, needs to be completed prior to the generator disassembly. Availability of funds and personnel to adequately administer and monitor the contracts should be considered.

(2) *Program Schedule Revisions*. Once all these interrelationships have been identified, an initial program schedule can be created as a broad initial overview for stakeholders. Many revisions to this schedule over the course of program execution can be expected.

(3) *System Interdependence versus Independence*. Some components or systems depend on each other for proper functioning and should be replaced concurrently. An example of an interdependent system is if the maximum power output of the turbine is being increased, then other powertrain components may need to be rehabilitated to operate the turbine at the increased power rating. Examples of independent systems include controls and protection, station service power, fire suppression, and raw water distribution systems.

(4) *Sequencing Considerations*. The detailed schedule should clearly illustrate the sequencing of the work to be performed and the predecessor and successor relationships between related activities, both within contracts and among contracts. Sequencing of equipment outages, especially unit outages, needs to be clearly illustrated.

(5) *Strategic Considerations*. Project work needs to change to accommodate the Contractor’s operations. An increase in powerhouse staff may be justified. When developing the schedule for the rehabilitation program of an operating powerhouse, consideration should be given to minimizing the impacts to day-to-day O&M activities of the Project. Lost generation should be reduced by minimizing the number and duration of unit outages associated with the rehabilitation work.

(6) *Longer Duration Critical Path Tasks*. When turbine replacement is in scope, it is typically the task with the longest duration. Total time to develop plans and specifications, award the contract, complete model testing, and then manufacture and install the first turbine is about six years. The entire generator rewind can usually be accomplished simultaneously with the turbine rehab without increasing the total timeline. After manufacturing the first new turbine runner, subsequent turbine runners can typically be manufactured in about six months. The time frame for disassembly, rehabilitation of retained turbine components, and reassembly varies depending on scope, but is not likely to take less than a year. Therefore, after installation of the first runner, the on-site activities and rehabilitation of retained turbine components becomes the primary critical path.

(7) *Logistic Considerations*. There are several logistics that can impact the sequencing of activities of a rehabilitation program, especially when multiple contracts are being executed simultaneously.

(a) Physical space in the powerhouse is limited, including but not limited to, major equipment laydown areas. When possible, contracts should be proactively scheduled to prevent competition for the same space and the potential claims and delays that can result.

(b) Having multiple contractors working on the same equipment or interfacing systems requires increased coordination, increases risk of costly changes if one contractor impacts the other contractor, and makes it difficult to assess responsibility for any damages or deficiencies. Limit this situation whenever possible, as well as USACE O&M work on equipment under the custody of a contractor, for similar reasons.

(c) Typically, it is possible to accomplish rehabilitation work on a unit within a single outage. However, accomplishing this large amount of work on diverse pieces of equipment and systems means that many different types of equipment, furnished by several different suppliers, need to be installed within a constrained time window.

1. One approach is to use multiple contracts but only one outage. A scenario that places only two installation contractors in the powerhouse is: (a) use separate supply contracts to acquire the governor, exciter, annunciation, control boards, bus, main unit breakers, and transformers well before the planned outage, then (b) award an installation contract to install all the Government-furnished equipment from these previous supply contracts, and (c) award a contract to supply and install the turbine and generator.
2. Another approach is to use multiple outages. For example, work on exciters, governors, station service, transformers, generator rewinds, turbine replacement, and main unit breakers could be performed under separate contracts, each with its own outage.

3–5. Report

a. General. After completion of the studies and assessments and the plan formulation, a final report for the proposed rehabilitation program should be prepared. This report captures and organizes the results of these activities for future reference. Keeping and maintaining design decision documentation is imperative. Inevitably, personnel will change over the course of the program, and this report provides a quick reference for those transitioning onto the job as to the scope and decisions previously made on the program.

b. Content. The report should capture not only what work is included in the rehabilitation program, but also what work was intentionally deferred, so that future readers will recognize that these systems and equipment were not overlooked. The final report should be structured such that the main body of the report is relatively short. Studies and assessments should be included as appendixes, along with any other memoranda or reports documenting critical decisions.

Chapter 4
Generator and Switchyard Configurations and Design

4–1. General

There are a variety of switching schemes or configurations for connecting one or more generators to one or more GSU transformers, and for the transformers to the transmission lines of the area utility or Federal Power Marketing Administration (PMA). The connection method from the GSU transformers to the area transmission lines typically involve either connections of one or more transmission lines to the GSU transformers through disconnect switches or breakers, or a transmission voltage switchyard is constructed adjacent to the powerhouse to facilitate the interconnections. This chapter covers both generator and transformer connection arrangements and transformer-to-transmission system connection schemes, but first focuses on basic design considerations when selecting various combinations of switching configurations.

4–2. Fault Current Calculations

a. *General*. Fault current calculations, using the method of symmetrical components, should be prepared for each one-line configuration 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 IEEE 399.

b. *Programs*. Many software programs are commercially available for performing these studies. The programs most often used by USACE include:

(1) ETAP.

(2) SKM Power Tools for Windows. This software may also be known by its legacy module names of DAPPER, CAPTOR, and A-FAULT.

(3) EasyPower.

c. *Criteria*. The following criteria should be used 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 kilovolt-amperes (kVA) short-circuit capacity available at the high-voltage terminals of the GSU transformer connected to the generator(s) under consideration, or external to the generator(s) under consideration if no step-up transformer is used.

(a) This should include the short-circuit capacity available from all other generators in the power plant, in addition to the short-circuit fault current contribution from the high-voltage transmission system.

(b) System short circuit capacity is usually readily available from system planners of the utility or the PMA to which the plant is or will be connected.

(2) *Calculating System Short-Circuit Capacity*. The North American Electric Reliability Corporation (NERC) requires utilities to have fault capacity data readily available for determining their fault contribution at the point of service (typically a USACE-owned switchyard or transformer). The transmission system short-circuit capacity can also be calculated with reasonable accuracy, when necessary, if sufficient information regarding the planned ultimate transmission system is available.

d. Estimating Power System Fault Current Contribution. When adequate information regarding the transmission system is unavailable, estimating methods must be used.

(1) In all cases, the system short-circuit capacity for use in the fault current calculations should be estimated on a conservative basis; more specifically, the estimate should be large enough to allow at least a 50 percent margin of error in the system contribution. This should provide a factor of safety, and also allow addition of transmission lines and generation capacity not presently planned or contemplated by system engineers and planners.

(2) Only in exceptional cases, such as small-capacity generating plants with only one or two connecting transmission lines, should the estimated ultimate system short-circuitry capacity be less than 1,000 MVA.

e. Power Transformer Impedances. 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 Chapter 11.

(1) 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. This lower value should be used in the calculations since the lower value of impedance results in greater fault current.

(2) 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. This is 7.44 percent less the 7.5 percent tolerance, which should be used in the calculations (lower value gives a higher fault current).

(3) Impedances for three-winding transformers and auto-transformers should also be adjusted for standard tolerance according to 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.

f. 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 (if necessary), should be used. Rated-voltage (saturated) values of the direct-axis transient reactance (X′d), the direct-axis sub-transient reactance (X"d), the negative-sequence reactance (X2), and the zero-sequence reactance (X0) are the four generator reactances required for use in the fault current calculations.

(1) If data is not available, Chapter 6 provides typical values of rated-voltage direct-axis sub-transient reactance for water-wheel generators based on machine size and speed.

(2) Design reactance values are interrelated with other specified machine values (such as short-circuit ratio, efficiency) so revised data should be incorporated into fault computations once a machine design has been selected.

(3) For generator uprates, an increase in generator MVA rating could increase the short-circuit current available. In most cases, a generator uprate involves only changes in the stator winding insulation system, and does not involve changes to the winding configuration, the air gap, or to the core (type of steel, slot size and number, etc.). In these cases, the per-unit sub-transient reactance X"d will change due to the MVA base change brought about by the new generator rating, but the actual X"d in ohms will not change appreciably. Differences in test results before and after uprates, once the change in MVA bases has been accounted for, can be due to differences in testing methods and inherent inaccuracy in testing methods.

4–3. Electrical One-Line Diagrams

a. General. The development of a plant electrical one-line (or single-line) diagram should be one of the first tasks in the preliminary design of the plant. 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 influence the rating of generators and, consequently, the rating of the turbines and the size of the powerhouse. In developing plant one-line diagram alternatives, review the industry practices and considerations described more fully in IEEE 666. Numbering for devices on single-line diagrams should comply with IEEE C37.2.

b. Evaluation Factors.

(1) Some factors to consider in evaluating one-line diagrams and switching arrangements include whether the plant will be staffed or remotely operated, equipment reliability, whether the plant will be used in a “peaking” versus a base load mode of operation, the need to maintain a minimum water flow past the plant, or whether there are restrictions on the rate of change of water flow past the plant.

(2) The base load mode implies a limited number of unit start-stop operations and fewer breaker operations than are required for peaking operation.

(3) Unmanned operation may require changes to ensure reliable protection and control, and simplicity of operation.

(4) If there are severe flow requirements, coupled with a need for continuous reliable power output, it may be necessary to consider the “unit” arrangement (see paragraph 4–4) because it provides the minimum loss of generation during first-contingency disturbances.

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

(1) Safety and reliability (including effects of planned and forced outages).

(2) Simplicity of operation, including reactive power generation of paired generators.

(3) Economic construction costs.

(4) Good technical performance.

(5) Readily maintainable (for example, critical components can be removed from service without shutting down multiple units or the balance of plant).

(6) Flexibility to deal with contingencies.

(7) Ability to accommodate system changes.

4–4. Generator (Unit) Switching Configurations

a. Unit Configuration. The “unit” configuration involves switching of the generator and transformer bank as a unit only with the circuit breakers on the high-voltage side of the GSU transformer, as shown in Figure 4–1. The unit configuration is well suited to small power systems where loss of large blocks of generation are problematic. The loss of a transformer bank or transmission line in all other switching arrangements means the loss of more than a single generation unit. Small power systems are systems unable to compensate for the loss of multiple units, as could occur using other arrangements. Note that very large generators may also be connected in a “unit” arrangement for much the same reason (loss of two or more very large generators for a single contingency may be problematic).

(1) The unit configuration makes maintenance outages simpler to arrange and is advantageous where the plant is located near the high-voltage switchyard allowing the transmission line from the GSU transformer to the switchyard to be reasonably short.

(2) This configuration, with a transformer and transmission line for each generator unit, tends to be higher in first cost (in terms of cost per generator) than configurations that have multiple generators on a single transformer and transmission line.

(3) Medium-voltage equipment for the unit systems includes bus leads from the generator to the GSU transformer and isolation disconnects for maintenance purposes.

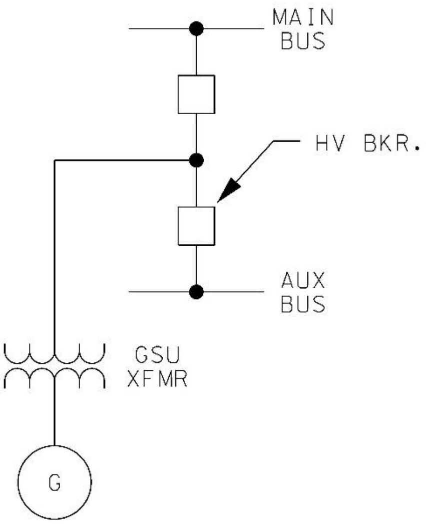


Figure 4–1. Unit switching configuration

b. Multiple Unit Configurations. Multiple unit configurations have two or more generators connected to the transformer.

(1) In larger power systems, where loss of larger blocks of generation may be tolerable or where the plant is interconnected to an extra high-voltage (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 arrangements are discussed in the following paragraphs.

(2) Two generators may be connected to a two-winding transformer bank through generator breakers in a “paired” switching configuration as shown in Figure 4–2. This arrangement has the advantage of requiring a single transmission line for two units, rather than the two lines required for a unit arrangement.

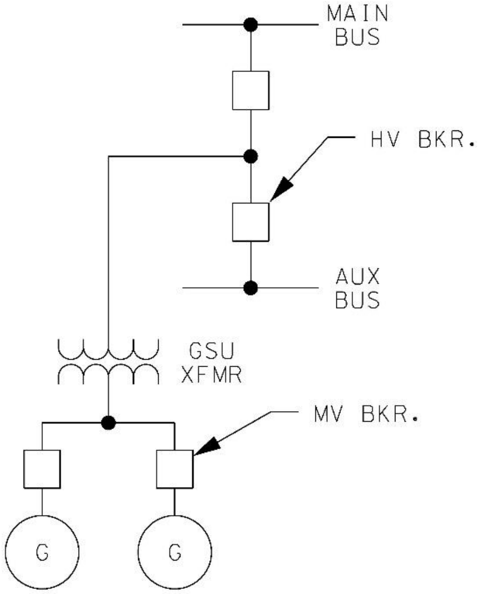


Figure 4–2. Paired switching configuration

(a) The paired configuration provides a clear savings in line right-of-way cost and maintenance.

(b) A single transformer, even though of higher rating, is also less costly than the two transformers needed for a unit system. The space requirement is also less than for two separate transformers. There are, however, trade-offs.

(c) A breaker is needed for each generator.

(d) The generator grounding and protection scheme becomes more complex.

(e) Additional space and equipment are needed for the generator medium-voltage (delta) bus connecting to the GSU transformer if the GSU is a bank of three single-phase transformers.

(f) An economic study should be made to justify the choice of design, and the transformer impedance requirements should be evaluated if the power system can deliver a large contribution to faults on the generator side of the transformer.

(3) For small generating plants, a “generator bus” configuration, which connects the generators through circuit breakers to the generator bus, may be appropriate, and is

shown in Figure 4–3. One or more GSU transformers (only one GSU is shown) can be connected to the generator bus, with or without a circuit breaker on the generator bus connection; however, using multiple transformers, each with its own circuit breaker, results in a very flexible operating arrangement.

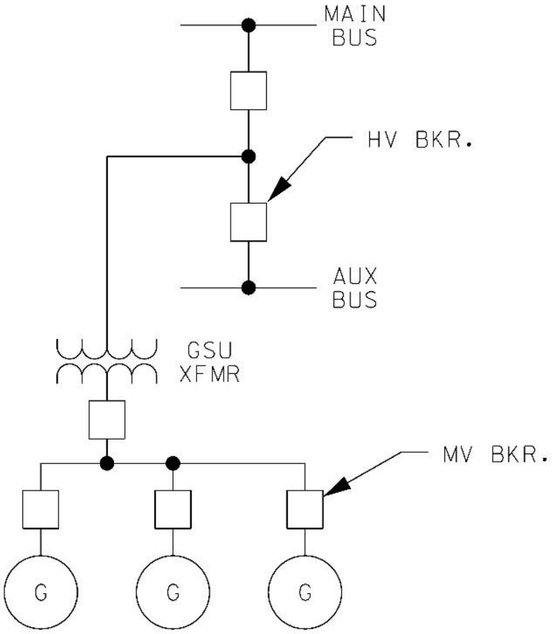


Figure 4–3. Generator bus configuration

(a) Individual GSU transformers (if more than one connects to the generator bus) with their own breakers can be taken out of service for testing or maintenance without taking the whole plant out of service.

(b) The impedances and voltage taps of multiple GSU transformers must be matched to avoid circulating currents.

(c) The protection scheme becomes more complex, which should be considered along with the other trade-offs when comparing this configuration with the other plant arrangements possible.

(4) Two or more generators can be connected to individual transformer banks through generator circuit breakers with the transformers bused through disconnect switches on the high-voltage side of the GSU transformers (a “paired high side” configuration) as shown in Figure 4–4. This arrangement has some of the advantages of the unit system.

(a) There is some loss of operational flexibility since transmission line maintenance requires taking all of the units out of service.

(b) A line fault results in sudden loss of all connected generators.

(c) The needs of the bulk power transmission system must be weighed against the economics of the arrangement.

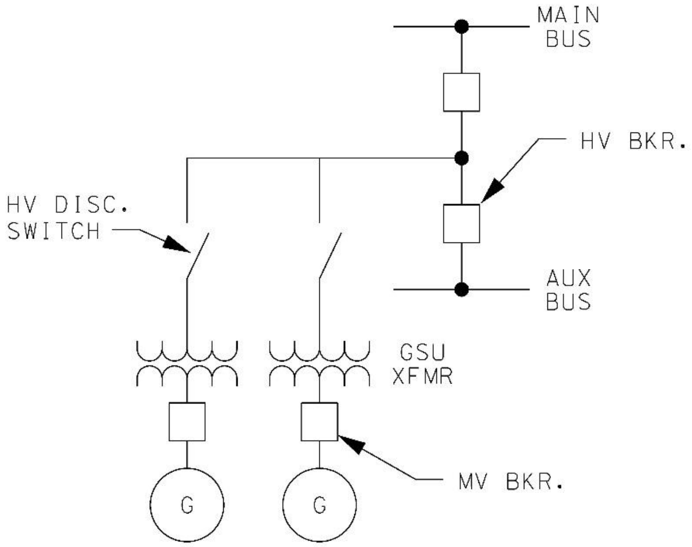


Figure 4–4. Paired high side configuration

(5) Two generators may be connected to a three-winding transformer bank in a “two-unit/three-winding” configuration as shown in Figure 4–5. The generators should be connected to the two low-voltage windings through generator breakers. 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.

(a) Transformer or line faults result in the potential loss to the bulk power transmission system of a relatively large block of generation.

(b) Transformer maintenance or testing needs require loss of the generating capacity of both units for the duration of the test or maintenance outage.

(6) Four generators may be connected to a three-winding transformer bank in a “four-unit/three-winding” configuration as shown in Figure 4–6. The generators are be connected to the two low-voltage windings through generator breakers. This arrangement has the same advantages and disadvantages as the two unit/three winding configuration, but it is advisable when the plant is connected to a bulk power distribution system capable of delivering high fault currents. It also finds application where plants are interconnected directly to an EHV grid.

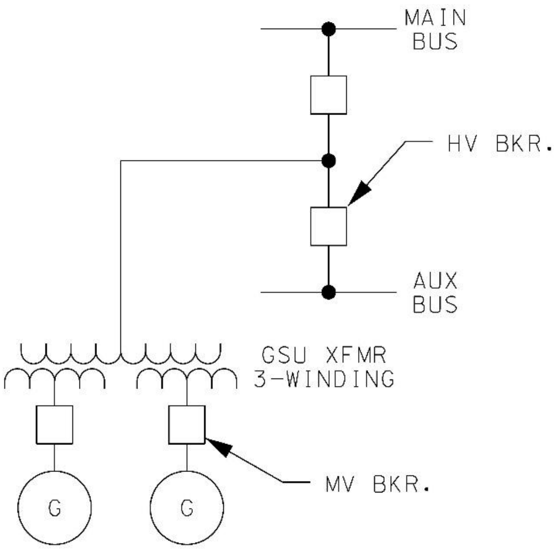


Figure 4–5. Two unit/three winding configuration

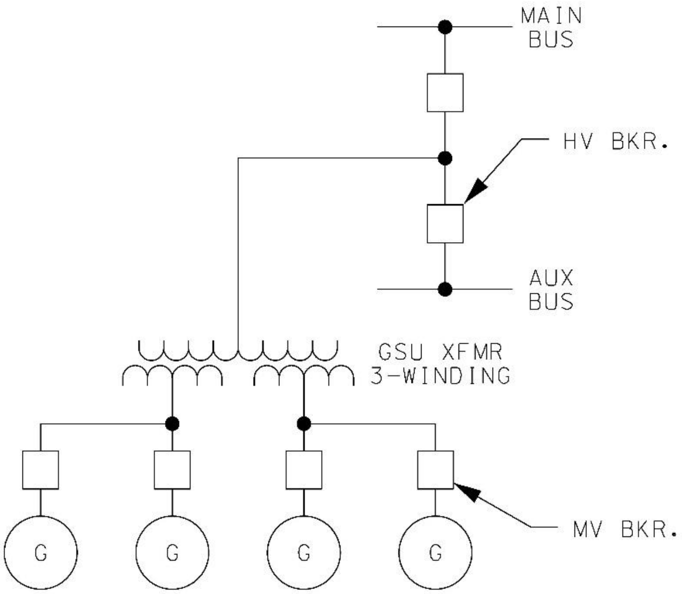


Figure 4–6. Four unit/three winding configuration

4–5. Switchyard Switching Configurations

The type of high-voltage switching configuration 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 brief discussion of the advantages and disadvantages of various high-voltage switching configurations is included in this chapter. For more detailed guidance and a discussion of advantages and disadvantages for each configuration, see IEEE 605.

a. Single Bus-Single Breaker Configuration. A single bus-single breaker (SBSB) configuration consists of one main bus that is energized at all times and to which all circuits are connected. There may be multiple sources from GSU transformers and multiple connections to the PMA or local utility, but all sources and lines are tied to the single bus. A bus fault or breaker failure trips the entire switchyard offline, with little opportunity to isolate the problem for repairs while still providing some service. See Figure 4–7 for a typical example.

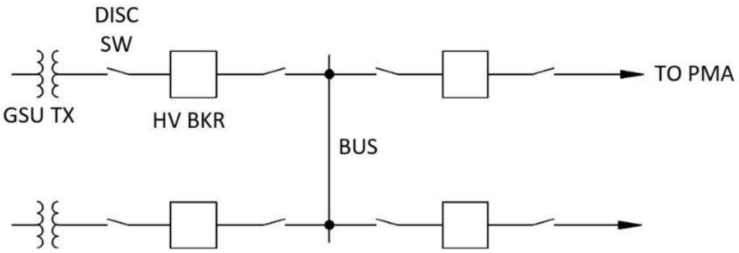


Figure 4–7. Typical single bus-single breaker configuration

(1) Advantages: Lowest cost, simple protective configuration.

(2) Disadvantages: Lowest reliability, any bus or breaker fault causes loss of switchyard with no means to isolate the problem, and breaker maintenance forces the associated element (line or GSU) out of service.

b. Single Bus-Single Breaker Sectionalized. A variation on the SBSB configuration is to have a sectionalizing breaker on the single bus, splitting the bus into two sections. A bus fault or breaker failure trips part of the switchyard, but the failure could then be isolated to only part of the bus to allow repairs. Failure of the sectionizing breakers still trips the entire switchyard. Each outgoing line still connects to the same main bus even with the sectionalizing breaker closed. See Figure 4–8 for an example.

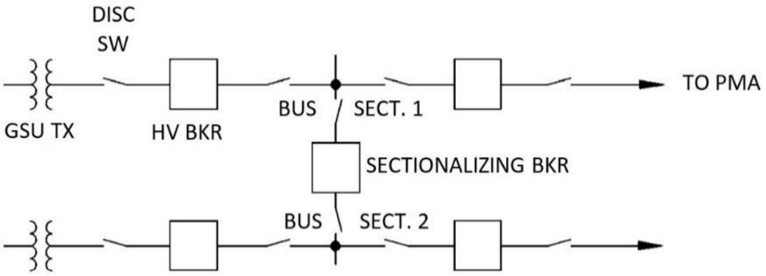


Figure 4–8. Typical single bus sectionalized configuration

(1) Advantages: Low cost, simple protection configuration.

(2) Disadvantages: Low reliability, any bus or breaker fault could cause loss of large portion of switchyard with limited means to isolate the problem, failure of sectionalizing breaker trips the entire switchyard, and breaker maintenance forces the associated element (line or GSU) out of service.

c. Main and Transfer Bus. A main and transfer bus configuration consists of two independent buses, one of which—the main bus—is normally energized. Under normal operating conditions, all outgoing circuits are powered from the main bus through their associated circuit breakers and switches. The transfer bus is used to provide service through the transfer bus transfer breaker when it becomes necessary to remove a breaker from service. Most USACE switchyards refer to the transfer bus as the auxiliary bus (though the recommended USACE configuration is often modified as described below). See Figure 4–9 for an example main and transfer bus.

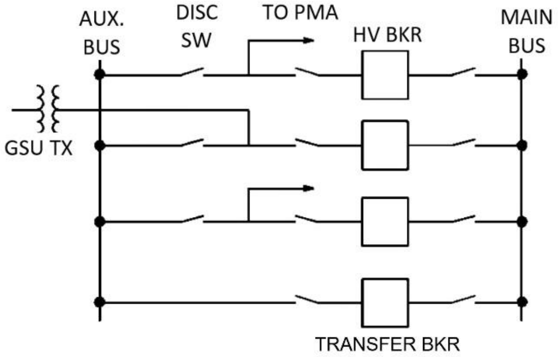


Figure 4–9. Typical main and transfer bus configuration

(1) Advantages: Low cost, continuity of service while a breaker is isolated for maintenance, relative ease of conversion to double bus-double breaker scheme.

(2) Disadvantages: Low reliability, any bus or breaker fault could cause loss of entire switchyard until the problem is isolated., The connection of any element to the transfer bus permanently (typically with an additional breaker) limits its functionality as a transfer bus.

d. Double Bus-Single Breaker Configuration. A double bus-single breaker configuration consists of two buses connected to each circuit breaker and a bus tie breaker. The tie breaker allows the transfer of circuits from one bus to the other by using the disconnect switches to isolate a circuit from either bus. A failure on one bus does not affect the other bus, allowing isolation of the failed bus while still delivering power. A bus tie breaker failure causes the outage of the entire system until the tie breaker can be isolated, creating a single bus system. See Figure 4–10 for an example.

(1) Advantages: Low cost, allows continuous service while a breaker is isolated for maintenance.

(2) Disadvantages: Low reliability, any bus or breaker fault could cause loss of entire switchyard until the problem is isolated, complex protection configuration.

e. Double Bus-Double Breaker Configuration. A double bus-double breaker (DBDB) configuration consists of two buses, both of which may be normally energized. Each circuit has two source buses available, with all breakers operated normally closed. Any circuit breaker can be removed from service without interruption of any other circuits. A fault on either bus causes no circuit outage. A breaker failure results in the loss of only one circuit. See Figure 4–11 for an example of a DBDB configuration.

(1) Advantages: Very high reliability and flexibility, a bus fault does not interrupt service, a breaker failure affects only that one circuit.

(2) Disadvantages: High cost.

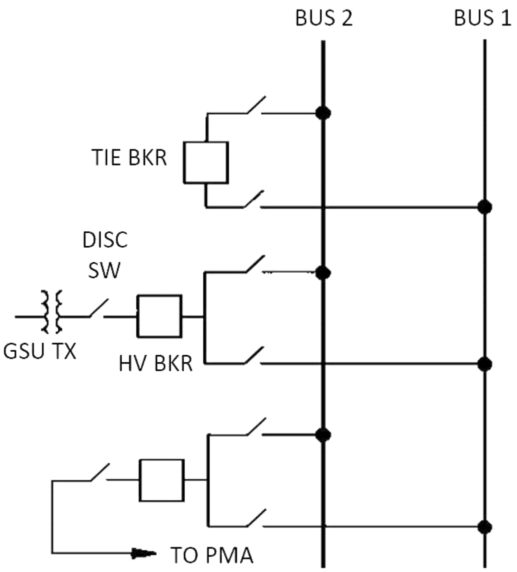


Figure 4–10. Typical double bus-single breaker configuration

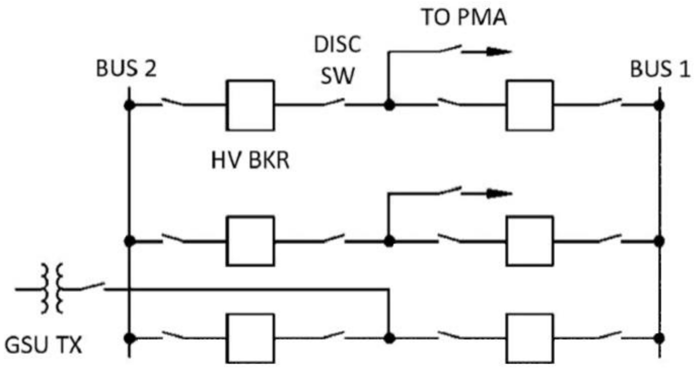


Figure 4–11. Typical double bus-double breaker configuration

f. *Breaker-and-A-Half Configuration*. The breaker-and-a-half arrangement provides two main buses, both normally energized. Between the buses are three circuit breakers and two circuits. This arrangement allows breaker maintenance without interruption of service. A fault on either bus causes 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. See Figure 4–12 for an example. This configuration is more typical of EHV switchyards and is not common among USACE switchyards.

(1) Advantages: High reliability and flexibility, a bus fault does not interrupt service, a breaker failure affects only that circuit.

(2) Disadvantages: Higher cost than single bus schemes.

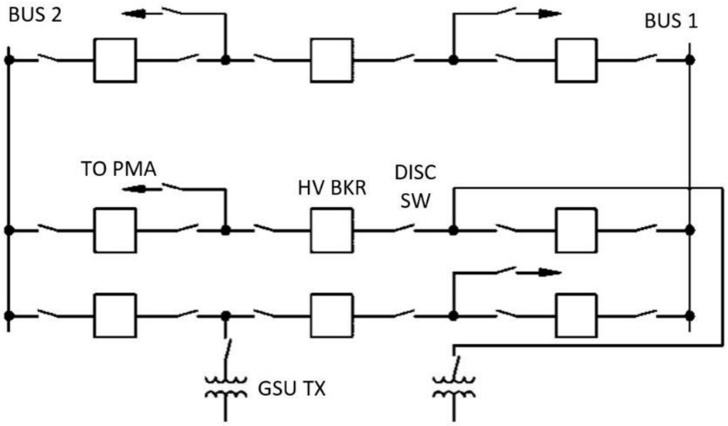


Figure 4–12. Typical breaker-and-a-half configuration

g. Ring Bus Configuration. The ring bus consists of a loop of bus 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 results in the removal of two bus sections from service. The ring bus arrangement allows circuit breaker maintenance without interruption of service to any circuit. See Figure 4–13 for an example.

(1) Advantages: High reliability and flexibility, a bus fault does not interrupt service, low cost.

(2) Disadvantages: Very complex relaying and control, a breaker failure affects the circuits on both sides of the breaker, maintenance outages open the ring bus leaving station subject to tripping for a line or bus fault.

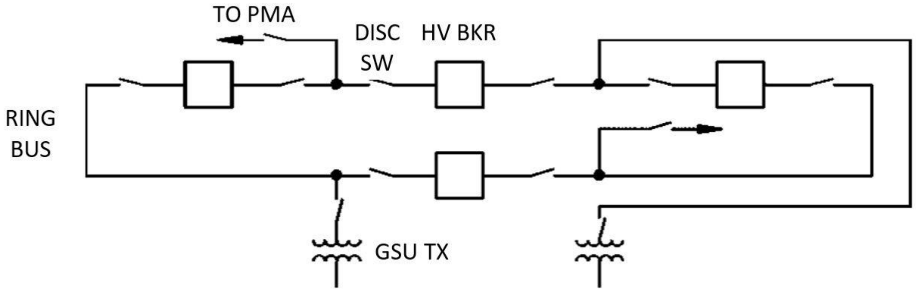


Figure 4–13. Typical ring bus configuration

h. Recommended Configuration. Most USACE switchyards use a hybrid mixture of the main and transfer configuration and double bus-double breaker configuration, in which the source circuits are “double breakered” to both buses, while the line circuits are “single breakered” to the main bus and connected by a motor-operated disconnect (MOD) switch to the transfer bus. See Figure 4–14 for an example. Bus configurations of this hybrid type afford the reliability of the DBDB configuration for some circuit elements on the main bus but not for the single-breakered elements on the auxiliary bus. The auxiliary bus connection typically uses a motor-operated disconnect switch for line isolation rather than a breaker. A common upgrade funded by many PMAs is to replace the MODs with breakers to make a pure DBDB configuration when funding is available.

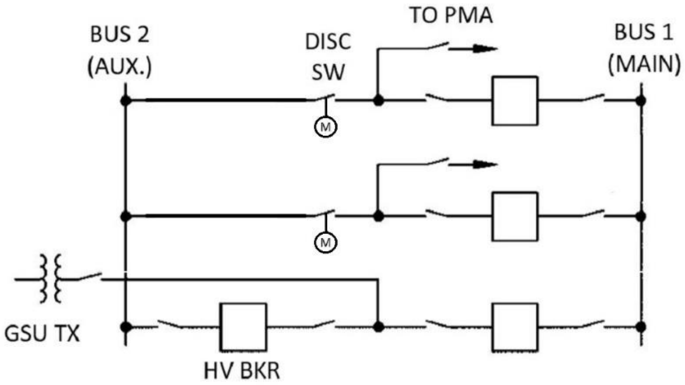


Figure 4–14. Typical hybrid configuration used by USACE

i. Some plants may be electrically located in the power system such that their transmission line-voltage buses become a connecting link for two or more lines in the power system network. At such plants, power may be “wheeled” through the switchyard by the PMAs or utility co-ops from one line to another when it is economically feasible to use a line under low demand to backfeed into another line under high demand. Switchyards where wheeling is expected may require a capacity to pass more power through it than is available from all main unit generators.

Chapter 5
Turbines and Pump Turbines

5–1. General

a. Mechanical design of turbines and pump turbines starts with selecting the number of units, type of units, power ratings, and operating characteristics.

b. Final design of turbines is a contractor responsibility and is included under the contract used for turbine procurement and installation. Coverage in this chapter is limited to considerations in preparation and completion of the project specifications.

c. Turbines are critical items in powerhouses, and warrant maximum effort to assure practical, well-coordinated specifications with reasonable assurance of responsive bidding. In addition to the guidance referenced above, the specifications should reflect USACE's experience with previous similar units and preliminary exchange of information and proposals with potential suppliers.

5–2. Turbine Runner Replacement Considerations

a. General.

(1) The following considerations are applicable to all turbine types.

(2) Additional considerations that are specific to certain turbine runner types are provided throughout this chapter.

(3) Chapter 3 provides guidance on appropriate studies and plans needed to properly scope a turbine runner replacement.

b. Self-Lubricating Materials.

(1) Due to performance and environmental considerations, using self-lubricating materials for wicket gate stem bushings in wet and/or dry conditions is recommended. Other common locations for replacing greased bronze bushings or dynamic bearing surfaces include the turbine operating ring and other distributor components. Uses of self-lubricating materials were identified in response to the Clean Water Act's goal of regulating pollutant discharges from point sources at hydropower facilities.

(2) The results of a testing program initiated in 1999 are detailed in Construction Engineering Research Laboratory (CERL) Technical Report 99-104. HDC maintains a database of self-lubricating materials approved for use in hydropower applications. Approved materials perform better than traditional greased bronze bushings from a friction and wear standpoint and do not require grease delivery for lubrication. As materials are continuously tested and considered for use, contact HDC Turbine Section for the most up-to-date list of approved materials for hydropower applications.

(3) Although no self-lubricating wicket gate stem bushings within the USACE fleet have experienced a full-service life, numerous installations have operated over 25 years without issue (as of this writing).

(4) Bushings made of self-lubricating materials can generally be machined to a tighter clearance due to the ability of the bushing material to locally deform.

(5) The installation of self-lubricating materials requires a hardened stainless-steel sliding surface with a tight surface finish tolerance. Specifics of material selection depend on application. Hardness values should be within 28–32 Rockwell C if using martensitic steel, but may go up to 42 Rockwell C for 17-4 PH Surface finish tolerances should be better than 16 microinch root-mean-square (rms).

c. Environmentally Acceptable Lubricants for Wicket Gate Applications.

(1) At the time of writing, environmentally acceptable lubricant (EAL) greases are acceptable only for wicket gate applications. When selecting candidate EAL greases, the defined EAL characteristics, performance requirements, and compatibility tests should be reviewed. See further details in EM 1110-2-1424 and Inland Navigation Design Center (INDC) Technical Report 2018-01. Further information can be found in the "Analysis of Environmentally Acceptable Lubricants for USACE Dams (Engineer Research and Development) and Mechanical Equipment Lubrication: Standardization and Sustainability (INDC)."

(2) To be considered an EAL, lubricants must meet specific criteria regarding toxicity, biodegradation, and non-bioaccumulation as stated in Environmental Protection Agency (EPA) 800-R-11-002. Additionally, lubricants represented as Vessel General Permit (VGP) compliant or approved/certified by Convention for the Protection of the Marine Environment of the North-East Atlantic (OSPAR) and European Union Ecolabel (EEL) may be considered as EALs.

(3) The performance properties for water washout, anti-corrosion, anti-wear, and oxidation stability must be tested for, in a lab or by manufacturer, according to American Society for Testing and Materials (ASTM) D1264, ASTM D4048, ASTM D2266, and ASTM D942, respectively. The recommended performance limits for candidate EALs are provided in Table 5–1.

Table 5–1
Performance property limits for candidate environmentally acceptable lubricants

Performance Tests	**ASTM D1264**	**ASTM D4048**	**ASTM D2266**	**ASTM D942**
	% Washout	Visual Score	Average Wear Scar	Mean Pressure Drop
Limits	≤ 5%	1 or 2	≤ 0.730	≤10.0

(4) Complete purging of the existing grease may not be feasible at all facilities. To reduce the chances of negative interactions between a new grease and existing grease (such as excessive thickening or thinning), compatibility testing between the existing grease and proposed new grease is recommended. ASTM D6185 provides guidance on compatibility tests and methods. HDC is required to review compatibility test results.

(5) Grease totalizing meters and pump counters should be installed so that the total grease discharge and number of pump operations can be compared between pre and post implementation.

(6) Further guidance and examples of approved EAL selections can be provided by HDC.

d. Environmentally Acceptable Lubricants for Turbine/Generator Applications.

(1) At the time of writing, EAL greases or fluids are not acceptable for other turbine/generator applications.

(2) USACE does not have ways of completely isolating oil systems, so any oil selected must be capable of functioning in static oil, as hydraulic oil (governor system), and in bearing systems. Testing is required to ensure compatibility with existing oils and ensure that all purposes are fulfilled.

e. Dissolved Oxygen Considerations.

(1) In locations where dissolved oxygen (DO) values are a concern, auto-venting turbine technology may be employed to introduce DO into the tailrace. The most preferred method uses distributed aeration techniques involving hollow turbine blades/struts. Other technologies such as peripheral and central aeration are less preferred, as they require more air admission to meet DO requirements and are less efficient. While more vendors possess the auto-venting technology, requiring this could limit competition. Factors that impact the amount of DO that can be introduced are flows, historic DO levels, and unit submergence. Note that the tailrace level varies with the river flow. The design of each system and the amount of DO that can be introduced are highly specialized and HDC should be consulted.

(2) Distributed auto-venting turbines require valving to be added to the headcover to draw air into the water passageway. This valving may add additional constraints in the turbine pit.

(3) The air that is added into the water passageway must be replenished to avoid negative air pressures. Considerations for replenishing air are needed. Refer to Chapter 36 for HVAC updates.

(4) To fabricate auto-venting turbines, considerations may be needed to allow bi-metal turbine runners.

f. Improved Fish Passage Design Runners. USACE has developed a process to design improved fish passage (IFP) turbines through the turbine survival program (TSP). The process includes a collaborative and iterative design effort between the Government and the Contractor and includes computational fluid dynamics (CFD) by the Contractor, turbine performance model testing by the Contractor, and observational model testing by the U.S. Army Engineer Research and Development Center (ERDC). This process is highly specialized and consultation with HDC and districts experienced with the process is necessary.

g. Uprating Considerations.

(1) *Shafting*. The 6,000 pounds per square inch (psi) or 41.4 Megapascal (MPa) max torsional stress criteria defined in paragraph 5–6b does not account for shaft geometry and deals only with membrane stresses or stresses in the bulk of the shafting. In addition, industry review of shaft stress design criteria indicates that this guidance is conservative. In the event that operation above the design criteria is desired, a more thorough, fatigue-based analysis must be completed prior to uprating the shafting. CEATI T092700-0357 addresses techniques and methodologies to complete this analysis.

(2) *Powertrain Limits*.

(a) Generator Uprate Study. As part of an uprate, the generator will require additional investigations to ensure that safe operation results from the increased thermal and mechanical loads. Coordinate with HDC to ensure appropriate scope.

(b) Powertrain Analysis. Even though the turbine and generator may be able to withstand continuous operation at uprated conditions, the remaining electrical powertrain from the generator barrel to the transmission lines should also be analyzed to ensure that it can withstand uprated conditions.

(3) *Downstream Flow Limits*. Uprated hydro turbine/generators often result in increased flow through the powerhouse at some time. This results in an increase in

tailwater elevation, which can have impacts on downstream channels. Consideration needs to be made for this increase in tailwater. Alternatively, high power operation may result in more frequent changes in unit operation from start to stop. Ramp rates should also be examined prior to uprating.

(4) *Turbine Hydraulic Limitations*. When considering uprating a turbine/generator, hydraulic limitations need to be considered. Specifically, at higher outputs, outlet flow cavitation may occur, and desired outputs may not be feasible without expensive recurring maintenance costs. Additionally, consider if the hydrology of the location means that additional water is available to be used at the uprated condition.

(5) *Servomotor Capacity*. At times, wicket gate and blade angle servomotor stroke or capacity or blade angle stroke or capacity may limit the ability to provide enough flow for the uprate. This should be evaluated prior to pursuing an uprate.

(6) *Crane Capacity/Lift Length Limits*. Uprating turbine/generators can result in changes in loading for bridge cranes. This may be due to increased runner weight, headcover changes, replaced shafting, etc. In addition, vertical lifts are constrained for major equipment. If lowering the centerline of the unit, consider crane vertical lifts, including lifting beams.

(7) *Transient Analysis*. Uprating hydro turbine/generators nearly always results in an increase in flow at maximum power. Due to this, there is either an increase in water hammer on quick closing of wicket gates, or there is an increase in rotational speed of the unit on loss of connection to the grid. Transient analysis that accounts for the water hammer pressure spike, wicket gate closing time, rotational inertia, water inertia, and rotational speed rise should be completed prior to operating at uprated conditions.

5–3. Francis-Type Turbines

Additional considerations pertinent to Francis-type turbines are as follows:

a. Turbine Runner Material Selection.

(1) Stainless steel is required for cavitation and corrosion protection.

(2) Martensitic stainless-steel (CA6NM) runners should be specified where possible. Austenitic stainless steel can be considered where applicable in highly corrosive environments. Bi-metal (both martensitic and austenitic) may be necessary for auto-venting turbines (see paragraph 5–2e).

(3) Castings and fabrications are both acceptable manufacturing techniques.

b. Francis Runner Fabrication-Partial Penetration Weld. Due to the sizing of typical USACE turbine/generators, fabrication of cast components is often necessary for Francis runners. Stress calculations should be performed, and stresses are kept below 1/3 yield and 1/5 ultimate, with a preference toward full penetration welding. Partial penetration welding is acceptable in locations where stress levels are below 5,000 psi (34.5 MPa) using von Mises stress combination. Using ASME Boiler and Pressure Vessel Code (BPVC) Section VIII, Division 2 stress criteria can be considered on a case-by-case basis.

c. Runner Wearing Rings. Modern Francis seal ring design features an integral runner sealing surface rather than a removable ring, and a one-piece aluminum bronze stationary ring. Aluminum bronze is the material of choice since it is gall resistant with stainless steels, which are preferred runner replacement materials. It is also highly resistant to erosion. One-piece stationary rings centrifugally cast or roll forged installed with an interference fit are preferred since they are more resistant to failure resulting from the pumping forces and resulting cyclic loading produced in the seal clearance.

5–4. Francis-Type Pump-Turbines

Considerations for Francis-type turbines listed in paragraph 5–3 are also applicable to Francis-type pump turbines. Due to the reversible nature of operation and stresses, more caution should be applied to pump-turbine applications with lower allowable stresses.

5–5. Adjustable-Blade Propeller Turbines

Additional considerations pertinent to adjustable-blade propeller-type turbines are as follows:

a. Turbine Runner Material Selection.

(1) Carbon steel hubs and stainless-steel blades should be specified where possible, with the surfaces of the hub that have contact with water painted. Stainless steel hubs can be considered where applicable in highly corrosive environments.

(2) Stainless steel or painted carbon steel are required for cavitation and corrosion protection. Chrome nickel overlay can be considered, especially in the shadow of the blade sweep.

(3) In the case of bolted-on blades, different material may be allowed between the blade and trunnion portions.

b. Blades.

(1) Blades can be constructed either with integral trunnions or in two pieces with a bolting flange between the blade and the trunnion. Bolted blades have the advantages of potentially being able to ship a shop-assembled hub, as well as requiring less space for turbine runner assembly.

(2) Blade shape geometry should be designed such that on the loss of governor pressure, the blades approach a steep position to reduce rotational speed and hydraulic thrust loads. This steep tendency should be validated during model testing.

c. Blade Servomotor.

(1) For new unit installations, a location requiring removal and disassembly of the runner to repair or replace the servomotor is not recommended. This normally rules out an upper hub location as an acceptable option. Location of the blade servomotor is a factor in selecting the governor operating pressure. Locating the servomotor in the runner cone below the blades is an acceptable alternative to the shaft location.

(2) For rehabilitations, all efforts should be made to maintain the existing blade servomotor to keep costs low. If the servomotor is located partially or fully inside the hub, considerations should be made to relocate the servomotor to the shafting if there is an environmental reason to do so, which includes fish passage or oil contamination.

(3) In both new and refurbishment applications, make sure the blade servomotor is adequately sized to ensure blade operation of the turbine runner.

(4) For Kaplan units, there may be advantage to reducing the volume of oil in the blade servomotor, and therefore higher pressure systems could be considered.

d. Head Cover Drain Pumps.

(1) *Overview*. Some units use head cover drain (or sump) pumps to remove water that passes by the packing and accumulates in the bottom of the head cover. Reliability

of the head cover drain pumps and power supply is of primary importance to provide maximum safeguard against flooding of the turbine guide bearing and a prolonged unit shutdown. Some water passes by the packing and accumulates in the bottom of the head cover. This water can then drain by gravity to the tailrace (if the turbine pit is above tailrace level), drain to a separate sump, or be pumped out using head cover drain (or sump) pumps.

(2) *Mechanical Design Memorandum*. The mechanical design memorandum should include a discussion on the reliability of the power supply of the head cover drain pumps and backup provisions. The memorandum should also include an evaluation of the seriousness of one or more units being out of service for the necessary cleanup operation.

(3) *Pump Configuration*.

(a) Typically, two electrical motor-driven pumps are provided for each unit. Pumps are typically driven in a lead-lag configuration, operating based on the level of water in the sump. Pumps are typically configured so one is powered from AC and the other is powered by DC. By using DC for one pump, the head cover drain system can continue to operate in situations where there is a loss of normal station power.

(b) If a reliable backup electrical source is not practicable to obtain, backup air operated pumps or water jet eductors may be justified.

(4) *Pump Types*.

(a) Pumps can be submersible type and located at the lowest elevation of the head cover or can be non-submersible and mounted higher up. For pumps that are not submersed, net positive suction head and self-priming capabilities must be considered during selection. Historically, centrifugal-type pumps have been used.

(b) Centrifugal-type pumps tend to emulsify any oil into the water, which reduces the effectiveness of the oil-water separator. If the water from the head cover drain pumps is being sent to an oil-water separator, an alternative type of pump, such as a positive displacement type, should be considered.

(5) *Controls*.

(a) Pump operation should be driven by the level of water in the sump. Mechanical float switches are typically used, but other level-sensing equipment can be used. Level-sensing equipment should be field adjustable.

(b) Level controls should be configured such that the AC pump starts when water level reaches a pre-determined height. If water level continues to rise, the second pump should turn on. If both pumps cannot keep up with inflow and the level continues to rise, an alarm signal should be sent to the control room.

e. Oil Head.

(1) Specify a static oil head when possible to maintain pressure inside the hub. In designs where a rotating compressor is used to establish hub pressure, consider removing rotating compressor oil heads and replacing with a static system to improve reliability and reduce risk of oil leaking into the turbine pit.

(2) Consider ceiling height and rigging when choosing the length of all oil head piping.

f. *Blade Trunnion Seals*.

(1) Specify redundant double-acting seals to seal from both directions (water side and oil side). For new installations, and for rehabilitation applications when practical, specify stainless-steel sealing surfaces on both sides of the trunnion seals (static and dynamic).

(2) New designs can incorporate monitoring leakage between both the water side and the oil side, which should be considered when replacing adjustable blade runners.

g. *Oil Leak Mitigation*.

(1) For new installations, and for rehabilitation applications when practical, specify double oil seals at all locations where oil can reach the water passageway. This may include removable cones, fastener connections, interface between shaft and hub, and access ports.

(2) For new installations, specify blind holes in the top of the hub for the shaft-to-hub fasteners and minimize number of leak paths.

h. *Turbine Oil*. Turbine oil is present in the turbine runner hub and blade servomotor, which is typically the same oil used throughout the unit, including the bearing sumps.

i. *Blade Opening Tendency*. Specify a blade opening tendency to ensure blades hydraulically move to a steep position to minimize rotational speed in the event that oil pressure is lost. This should be evaluated to at least the favorable blade and gate positions.

5–6. Turbine Design

a. *Turbine Model Test*. Consideration should be made to perform turbine model testing to better predict prototype (performance of the scaled-up diameter to the field installation) turbine performance. If the expense of a model test is not warranted due to smaller size of unit, CFD analysis should be completed.

b. *Shafting.*

(1) *Shaft Stress Limits*. The minimum shaft diameter for new construction should be computed based on the maximum allowable combined stress 6,000 psi (41 MPa). The stress should be combined using the maximum torsional stress from Mohr's circle. Mohr's circle should combine the following stresses: stress due to the weight of all rotating parts carried by the shaft; stress created by the maximum steady-state operating hydraulic thrust; and the stress produced by the maximum torque the turbine is allowed to produce, normally the maximum continuous duty rating (MCDR) at a power factor (PF) of 1.0. For rehabilitations, non-destructive testing (NDT) should be completed in high-stress areas (fillet radii, changes in profile, sharp transitions, etc.) and regions subject to corrosion should be machined to remove damage and then painted.

(2) *Shaft Inspection Hole*. The minimum diameter of the axial hole through the turbine shaft for inspection purposes is about 4 inches (in.) (100 mm). Holes that have diameters of 6–8 in. (150–200 mm) are normally specified on the larger shafts where the reduction in strength is insignificant. The larger holes expedite inspection and remove additional core material prone to shrinkage cavities.

c. *Wicket Gates*.

(1) Stainless steel or painted carbon steel can be specified for new wicket gates. Commonly, martensitic stainless steels such as CA6NM are specified for increased

strength but provide less corrosion resistance than austenitic. Consider water quality when deciding on material. Galvanic attack may also play into consideration for avoiding stainless steel and using painted carbon, as were historic designs. Additional guidance can also be sought from the Mobile District Corrosion and Cathodic Protection Center.

(2) For both new and refurbished gates, ensure minimal clearance, less than 0.003 in. (0.076 mm), heel-to-toe mating surfaces, specify end face materials to minimize galling with head cover and bottom ring facing plates, and consider stem material properties for mating with wicket gate bushings.

(3) Specific hardness and surface finish values are required for self-lubricating bushings and should be coordinated with the requirements of the selected self-lubricating material.

(4) Wicket gate stem sleeves are preferred, but consideration can be made for no sleeves if the material can achieve hardness and surface finish requirements.

(5) Wicket gates can be fabricated or cast. All stainless-steel welding should use filler rod with carbon content less than 0.03 percent. Welding should comply with ASME Section VIII Division 1.

d. Wicket Gate Closing Tendency.

(1) New wicket gate designs should be such that on the loss of governor servomotor pressure, the gates close. This closing tendency typically increases until near peak servomotor stroke and then relaxes past peak. On the extremities toward speed-no-load and maximum power, the closing tendency may be lost. Note that the closing tendency varies with head.

(2) Physical blocking mechanisms should be designed to limit any operation that could result in wicket gates opening on loss of governor pressure.

e. Wicket Gate Shear Pins and Links.

(1) Different designs employ different methods of protecting the wicket gate stems with sacrificial component. Some designs use shear links directly in the wicket gate operating mechanism, whereas others use shear pins.

(2) Where shear pins are used, a pneumatic system for detecting a broken shear pin is not normally installed until operating experience indicates a need (such as frequent shear pin failures). As units become remotely operated, consideration should be given to adding shear pin detection systems.

f. Wicket Gate Servomotor Pressure.

(1) Nominal system operating pressures (high end of operating range) range from 300 to 2,500 psi (2.1 to 17.2 MPa). Optimum pressure is dependent on many factors, including required pump displacement, pipe sizes, cost of hydraulic components, pumping horsepower, tank sizes, blade and gate servomotor sizes and location, volume of oil, and service experience.

(2) Evaluation should be based on overall cost of the turbine and governor system. The evaluation must be based on advance information obtained from potential turbine and governor suppliers since the turbine and governor are normally obtained under separate contracts.

(3) System piping, fittings, and packing appropriate for the operating pressure should be specified. A standard pressure should be specified. See Chapter 22 for piping requirements.

g. Wicket Gate Stem Seals. Braided packing was traditionally used, and can be specified for use, in refurbished units. Stacked “u” or lip-type seals may be specified, however, “u” or lip seals require a better housing surface finish with a tighter dimensional tolerance.

h. Wicket Gate Locking Device. A manual device is satisfactory for the open gate position. An automatic device for the closed gate position should be provided for all units to permit automatic locking on unit shutdown. Special considerations may be needed for remote operations to ensure locking mechanisms are effective and appropriately designed.

i. Material Considerations – Large Castings.

(1) Large components constructed of cast steel or cast iron can have quality issues ranging from voids, cracks, and lack of material strength. Large castings are typically defined as components such as head covers, bottom rings, bearing housings, and bearing shells. Due to difficulty in repairing defects in large components constructed from cast steel or cast iron, a consideration for replacing large castings with new components should be made during pre-rehabilitation planning. The designer should weigh the costs of performing additional repairs as well as schedule considerations on rehabilitating large castings against the costs of replacing the large component with a new fabrication or new casting. Casting acceptance criteria are defined in Cahier des Charges Hydrauliques (CCH) 70-4.

(2) To better inform the designer, if possible, a material sample taken from the component can be used to perform chemical and mechanical strength testing of the base metal. Additionally, if the component can be inspected for cracks using NDT methods before any planned rehabilitation, any revealed flaws can be useful in determining whether it is cost effective to repair the component or replace altogether.

(3) If new large castings are included in the rehabilitation, coupons should be included for material chemical and mechanical performance verification. Coupon removal should account for the entire manufacturing process, including heat treatment.

j. Facing Plates and Wicket Gate Seals. Facing plates above and below the wicket gate end faces are required. Choose a material that minimizes galling with the wicket gate end face material. Wicket gate seals can be considered to minimize leakage but are typically not necessary for projects with gross heads less than 300 feet or 91 meters.

k. Runaway. Coordinate runaway speed of turbine with mechanical limits of the generator. The generator is typically the most common the limiting feature during a runaway event (see Chapter 6).

l. Stay Ring.

(1) *Internal Pressure*. The stay ring should be designed for an internal pressure based on maximum pool head plus water hammer.

(2) *Grout Holes*. Holes required for placing grout under the stay ring are normally 50 mm (2 in.) in diameter. A diameter of 3/4 in. (20 mm) is satisfactory for vent holes.

m. Spiral Case and Spiral Case Extension. The specific requirement depends on the following: the need for a field hydrostatic test; the need for a valve at the end of the penstock; and the method of connecting spiral case extension to the penstock or penstock valve.

(1) *Hydrostatic Test*.

(a) Standard practice is to require a field hydrostatic test on all units requiring field welding. Elimination of field welding is practical only with very small cases permitting full shop assembly and shipping. The test should be specified at 150 percent of design head, including water hammer. When a hydrostatic test is specified, the alternative of magnetic particle inspection for circumferential shop and field-welded joints may be used.

(b) A field hydrostatic test also requires the alternative of providing a test pump and sealing off devices at the stay ring opening and inlet end of the spiral case extension. Also, when a field hydrostatic test is performed, the embedment of the case is performed while pressurized, and the test pump is used to maintain design pressure in the case. The relief valve specified should be capable of being set at both the design pressure and test pressure. The pressure alarm should be actuated at a 10 psi or 68.9 kilopascal (kPa) drop below design pressure.

(c) If circumstances are such that embedment with pressurized spiral case is impracticable, a mastic blanket covering the spiral case and extension is usually required to minimize the transmittal of operating head load to the concrete. An alternative requiring an additional 3 in. (76 mm) length of spiral case extension is necessary for cutting and finishing when removing a test head.

(2) *Penstock Valve*. See Chapter 19 for the requirements pertaining to penstock valves.

(3) *Connection to Spiral Case Extension*. The choice of a flexible sleeve-type coupling or a welded joint for connecting the spiral case extension to the penstock valve or penstock depends primarily on structural considerations. These considerations involve the most practicable point at which to take the closed valve reaction and the probability of differential settlement or other structural factors affecting alignment of the penstock and spiral case extension.

(a) With Penstock Valve. Where a penstock valve is used, the reaction of the closed valve is generally taken by the penstock and a flexible coupling provided to connect the valve to the spiral case extension. This connection requires a straight section of penstock extension with tolerances to meet the coupling requirements and long enough to permit assembly and disassembly. Guide specification options are included for obtaining the straight section. A welded connection for valve-to-spiral case extension is satisfactory with closed valve reaction taken by the penstock and structural and foundation conditions indicating no potential misalignment problems.

(b) Without Penstock Valve. A welded connection should generally be used unless structural and foundation conditions indicate possible misalignment problems. Where a flexible coupling is indicated, the straight penstock section is required as with the valve-type installation.

(4) *Service Water*. A service water connection on the spiral case extension is primarily for generator air coolers and generator and turbine bearing coolers. Unit gland water may also be from the service water connection, and in some powerhouses, raw water for other powerhouse requirements is obtained from this source. The connection size specified should be based on preliminary estimates of cooling water requirements by potential generator and turbine bidders, requirements at existing projects, crossover requirements, and the proposed powerhouse piping system. A connection is not

required where a tailwater pumped supply is justified. If piping and valve location considerations warrant, the supply connection may be specified on the spiral case rather than on the spiral case extension.

(5) *Drain*. The spiral case-extension drain should be sized according to the considerations noted in Chapter 27.

n. Embedded Piezometer Piping.

(1) The embedded piezometer piping connects the piezometer tap to an outlet valve typically found in the powerhouse. The piezometer tap is a smooth opening on the conduit wall normal to the water that can measure the pressure head directly in feet of water. The pressure head measurement is used in a variety of powerhouse applications to determine flows, water levels, and differential heads.

(2) Turbine piezometer taps are provided for pressure-time and Winter-Kennedy tests and to operate flow meters. Pressure-time piezometer taps and embedded piping should be provided for all turbines where the penstock is of sufficient length to meet the minimum requirements. Requirements are found in ASME Performance Test Code (PTC) 18 (most propeller-type units do not have suitable intakes for Gibson tests). Winter-Kennedy piezometer taps and embedded piping for Winter-Kennedy tests should be provided on all propeller and Francis-type units.

(3) Taps are located on a radial plane near the middle of the first quadrant of the spiral case. One tap is located on the outside wall at the spiral case horizontal center line, while one to three taps are located on the inside wall above the stay ring. One outer and one inner tap is required for the tests. However, two additional inner taps are normally provided to aid in achieving the appropriate pressure differential. In steel spiral cases, the turbine contractor normally installs the taps. In concrete semi-spiral cases, the taps are furnished and installed under the construction contract.

(4) Net head piezometers upstream of the spiral case are required on all units for use in conjunction with tailwater sensors to determine net head on the unit. For Francis units, taps are located by the turbine contractor in the spiral case entrance or spiral case extension. Four or more taps are provided in the conduit wall, equally spaced on a plane normal to the flow. Detail of the location and number of taps is determined by the turbine manufacturer. For propeller type units, two taps are located opposite each other in the sidewalls of the turbine intake, about halfway between the floor and roof and 5 to 10 ft (1.5 to 3 m) upstream of the upstream intersection of the cone with the intake floor and roof.

o. Air Depression Connection. Where an air depression system is planned for depressing the residual water in the turbine passage below the runner, or is a future probability, a flanged connection in the head cover should be provided. Considerations pertinent to sizing the connection are discussed in Chapter 25.

p. Pit Liner.

(1) The minimum elevation of the top of the pit liner should be specified to be approximately 2 ft (0.6 m) above the servomotor elevation. Minimum plate thickness should be 1/2 in. (13 mm) to permit tapped holes for the mounting of piping and equipment.

(2) One personnel entrance to the turbine pit is sufficient unless safety regulations require an additional access for emergency escape.

q. Draft Tube Liner. The minimum draft tube liner thickness is usually specified at 5/8–3/4 in. (16–19 mm) depending on the draft tube size. The liner should extend down to protect concrete from water velocities over 30 ft per second (fps) (9 meters per second [m/s]) and a minimum of 3 ft (0.9 m) below the main door.

r. Turbine Guide Bearings.

(1) *Turbine Guide Bearing Cooling*. Turbine Guide bearings may be cooled using passive or active means. Passive cooling allows the heat of the oil to be cooled through the surrounding steel surfaces, which are cooled by the water passageway. Active cooling uses a heat exchanger to cool the oil. Turbine guide bearing cooling systems are similar to the thrust or generator guide bearing systems. See Chapter 6 for additional details.

(2) *Turbine Guide Bearing Lubrication*. Hydrodynamic bearings that use the spinning action of the shaft to circulate oil are preferred for reliability reasons wherever practical. Low-pressure hydrostatic lubrication systems are used when self-lubricating bearings are not practical or possible.

(a) Configuration. When a pressurized system is used, a pump draws oil from the sump and injects it into the bearing. Heat exchangers can be incorporated into the lubrication system to provide active cooling of the lubricating oil. When a non-pressurized system is used, a pump draws oil from the sump and injects on top of the bearing, allowing gravity and centrifugal friction forces to draw the oil into the bearing.

(b) Pumps. Two fixed-flow rate, positive displacement pumps driven by electric motors are typically provided. Rotary screw or gear pumps are the preferred type. One pump is driven by AC power and the other by DC. Having one pump driven by DC power allows the lubrication system to run off the powerhouse battery in situations where normal or preferred station power is lost.

(c) Controls. Control of the lubrication system should be incorporated into the unit’s start-stop sequence. The system should be started prior to starting the unit. Pressure, level, or flow switches should be used to verify the system is correctly operating. Controls should be configured such that the DC pump automatically comes on if the AC pump fails or if there is a loss of AC power.

(3) *Oil Sump Drainage Pump*. An oil sump drainage pump is required when it is not practicable to drain the sump to the oil storage room by gravity. Capacity should be based on draining the sump in 3-4 hours. The installed pump option is preferred over a portable pump for convenience and savings in operational hours.

(4) *Babbitted Bearings*. At the time of this writing, babbitted bearings are preferred for turbine guide bearings. Acceptable alloys are ASTM B23 Alloy 2 and 3.

s. Lifting Devices.

(1) The original turbine manufacturer provided custom designed lifting devices to allow the powerhouse crane to lift the turbine-generator components. The original design, documentation, and markings for these BTH lifting devices may not meet current standards of EM 385-1-1, ASME B30.20, and ASME BTH-1. Ensure that all turbine lifting devices are fully compliant with relevant BTH criteria defined in the aforementioned standards. These requirements apply to every piece of equipment used to lift turbine components, even smaller pieces such as threaded rods. See Chapter 20 for additional lifting device requirements.

(2) Verification of BTH compliance should be completed prior to a rehabilitation contract. Complete documentation should include calculations verifying rated capacity, inspection of devices both to verify details for the analysis and to look for flaws, and a record of 125 percent load test of BTH devices. Lifting devices should also be marked according to ASME B30.20.

Chapter 6
Generators and Motor-Generators

6–1. General

a. Design Constraints. The hydraulic turbine-driven generators used in USACE powerhouses are synchronous, salient pole, alternating-current machines that produce electrical energy by the transformation of mechanical energy. The electrical and mechanical design of each generator must conform to the electrical requirements of the power system and the hydraulic requirements of its specific plant. They are most typically designed and procured per IEEE C50.12 requirements, in addition to more detailed specification requirements.

b. Design Characteristics. Hydroelectric generators are custom designed to match the hydraulic turbine prime mover. Many of the generator characteristics (short-circuit ratio, reactances) can be varied to some extent to suit specific plant requirements and power 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 used in the design only if their need justifies the increased cost.

6–2. Electrical Characteristics

a. Capacity and Power Factor. Generator capacity is commonly expressed in kVA, at a given (“rated”) PF. The power factor of the generator is determined considering the requirements of the power system to which it will connect. These requirements include 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.

b. Generator Power Output Rating. The kilowatt rating of the generator should be compatible with the hp rating of the turbine. In determining generator capacity, possible future changes to the project, such as increasing turbine output capability, should be considered. See detailed discussion on turbines in Chapter 5.

c. Generator Capability Curves.

(1) Generator capability curves represent various factors that limit generator operation within a defined region. They define generator capabilities when the generator is operated within rated generator conditions (terminal voltage, frequency, and cooling air temperature). There are several current, voltage, and other limiter and protective devices that impact the generator capabilities as shown on the capability curve. The settings for these limiters and devices need to be well-coordinated to allow maximal use of the safe operating range of the generator. Figure 6–1 shows an example capability curve for a hydroelectric generator. Note that for a motor-generator, the curves are generally mirrored across the megavolt-ampere-reactive (MVAR) axis such that the stator MVA curve is circular.

(2) *Rated Stator Megavolt-Amperes*. The outermost semicircle is determined by the generator rated kVA or MVA. This is a thermal limitation of the stator winding insulation, based on the insulation class and allowable temperature rise during operation. Operation above these limits shortens the life of the winding insulation, as the elevated temperatures (driven by stator current) will degrade the winding insulation more rapidly. This curve is independent of terminal voltage when the machine is operated between 95 percent and 105 percent of nominal voltage.

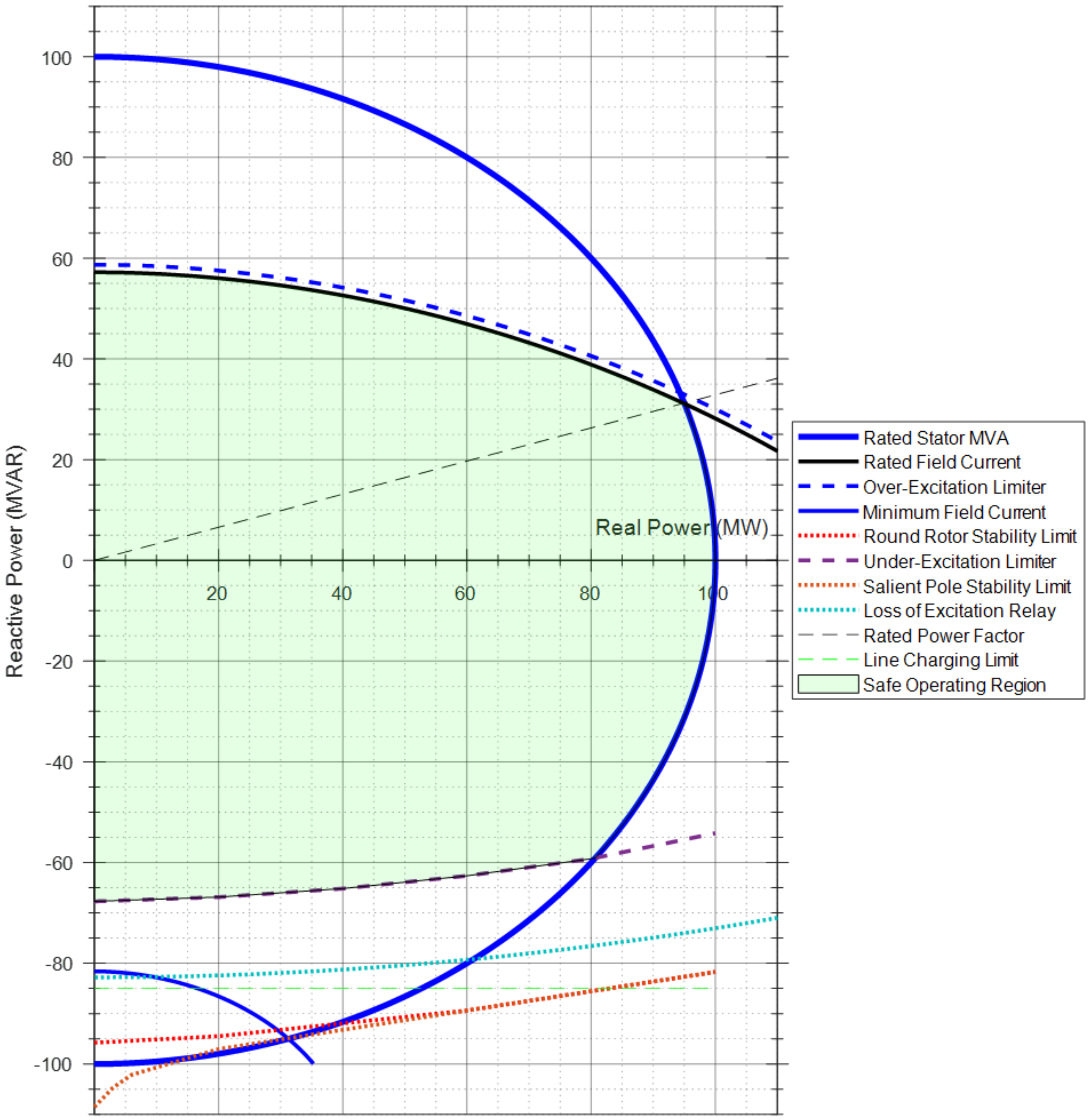


Figure 6–1. Example generator capability curve

(3) *Rated Power Factor*. A line is drawn from the origin to the rated power factor operating point on the capability curve as well. This line, in the overexcited region, defines the intersection of the rated field current curve (when drawn at rated terminal voltage) with the stator rated MVA curve. A generator with a lower rated power factor has a higher reactive power output capability at most real power output levels.

(4) *Rated Field Current*. The uppermost generator limit in the overexcited region is determined by field winding temperatures. This curve typically intersects the stator-rated MVA curve at the same point as the rated power factor line. The field winding heating

limit is a thermal limitation based on the rated temperature rise of the field winding. Operation above this line results in higher than rated field winding temperatures and degradation of the insulation.

(5) *Over-Excitation Limiter*. To prevent field current from exceeding the thermal capability of the field winding, an over-excitation limiter is implemented as a feature of excitation systems. Refer to Chapter 8 for additional information on excitation systems and their interactions with generator capabilities. This limiter is generally an inverse-time overcurrent-type limiter, which acts to limit field current more quickly with greater field current values. Limiters are generally coordinated based on an assumed field winding heating limits from the IEEE C50.13 standard for cylindrical-rotor machines.

(6) *Steady-State Stability Limits*. Various methods of calculating the steady-state stability limits of synchronous generators have been used in the past, and these methods account for differences between round rotor machines and salient pole machines. Hydroelectric generators are generally salient pole machines. However, the round rotor steady-state stability limit calculation is more conservative and is much more straightforward to calculate. Figure 6–1 shows examples of both types of curves. It is worth noting that steady-state stability limits are calculated assuming manual operation of the exciter, and numerous sources suggest that concerns over steady-state stability limits are unfounded when using a continuous, fast-acting automatic voltage regulator.

(7) *Line-Charging Capacity*. A generator that may energize relatively long transmission lines is typically required to absorb reactive power (operate in an under-excited condition) due to the capacitive characteristic of the unloaded transmission line. 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 times its normal rating multiplied by the short-circuit ratio but cannot be assumed to exceed its stator winding kVA rating. 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 6–1), making it more susceptible to loss of synchronism or pole slipping in the event of a system disturbance.

(8) *Minimum Field Current Limit*. A minimum field current limiter may be implemented within some excitation systems. This limiter has historically been in place to prevent operating with insufficient current to guarantee successful thyristor operation within static exciters. It may also be implemented to provide additional assurance against loss of excitation or similar stability concerns. Refer to Chapter 8 for further details regarding excitation systems.

(9) *Core End Region Heating*. In round rotor machines operating in the under-excited region of the capability curve, air-gap leakage flux patterns are affected by the rotor winding retaining ring and can enter the stator core. The direction of this flux at the stator core ends is perpendicular to the stator laminations, resulting in increased eddy currents and resulting heating. This air-gap leakage flux is a problem only during under-excited operation. On salient pole rotor machines, the possibility of excessive core end heating is not eliminated because there is some air-gap leakage flux that leaves the end

of the stator core in all machine designs. Generally, the risk of excessive core end region heating in salient pole machines is relatively low due to the different construction, though original manufacturer recommendations should be respected unless verified to be unnecessarily limiting.

(10) *Loss of Excitation Relay*. The loss of excitation relay element (device 40) acts to trip the generator in case of a detected condition of loss of excitation. This is to prevent against loss of synchronism and instability. This element is impedance based so the negative MVAR limit adjusts based on measured terminal voltage.

(11) *Under-Excitation Limiter*. An under-excitation limiter is commonly employed in excitation systems to prevent operation in regions that may result in protective relay action tripping the generator and risk of instability. These limiters may be based on calculated load angle or otherwise calculation based but are typically implemented in the form of real and reactive power lookup tables. The limiter is commonly adjusted based on generator terminal voltage to account for similar movement of the loss of excitation relay elements (which are impedance based).

d. Generator Voltage.

(1) For new machines, the voltage of large, low-speed generators should be as high as the economy of machine design and the availability of switching equipment permits. Generators with voltage ratings above 16.5 kV have been furnished, but manufacturing practices generally dictate an upper voltage limit of 13.8 kV for machines up through 250 MVA rating. For generator refurbishments, changing the nominal voltage of the generator is not typically considered due to the existing machine design and the already-established ratings of connected equipment.

(2) Based on required generator reactances, size, and inertia, 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. Generators of less than 5,000 kVA should be designed for 480V, 2,400V, or 4,160V, depending on the facilities connecting the generator to its load.

e. Insulation.

(1) A primary feature of stator winding design and manufacturing is the insulation used to isolate the energized copper conductors from the grounded stator core. This insulation system is composed of insulating materials that are consolidated using various types of resins and binding materials. The specific materials and manufacturing approaches have evolved over time, and still vary somewhat between manufacturers. Insulation systems are designed and tested to operate for a specified minimum duration at a given temperature, which defines their temperature class.

(2) *Historical Stator Winding Manufacturing Methods*.

(a) Older generator stator windings may be either Class 130 (B) or Class 155 (F) insulation systems as defined in IEEE Standard C50.12, which was chosen based on the expected use of the generator. If the generator was expected to operate continuously at or near rated load, then the Class 155 (F) insulation system was specified (assuming it was available at the time). For generators that were expected to operate below rated load most of the time, and at or near full load for only limited periods, a Class 130 (B) insulation system was typically specified.

(b) Insulation systems using a polyester resin as a binder have historically been used, though for early systems of this type, the softening temperature of the polyester resin was close to the Class 155 (F) temperature limit. Polyester resin has the advantage of being slightly more flexible than most epoxy systems. This slight flexibility is an advantage when installing multi-turn coils in stator slots in small-diameter generators. Polyester has no advantage over epoxy if the stator winding is the Roebel bar type. Epoxy is usually preferred because of its higher glass transition temperature (T_g).

(3) *Modern Stator Winding Manufacturing Methods*.

(a) New generator stator windings are supplied with Class 155 (F) insulation materials, with the observable temperature rise of the stator winding at the rated output required to meet the temperature limits defined in the specifications. IEEE Standard C50.12 provides guidance on allowable temperature rise as measured by embedded detectors based on insulation class and operating voltage. The choice of the required temperature rise over ambient temperature depends on machine size, how the machine will be operated, and desired winding life. Specifications are commonly prepared with the intent of achieving a stator winding life expectancy of 40 years or more under anticipated operating conditions. This results in a temperature rise requirement of 75 ºC (167 ºF) rise over a 40 ºC (104 ºF) ambient.

(b) Modern stator winding insulation systems consist of a mica-based ground wall insulation with a suitable insulation binder, generally a thermosetting epoxy resin material. These thermosetting systems achieve dielectric strengths equivalent to or greater than that of older thermoplastic insulation systems with less thickness than the older systems. This allows additional copper content within the coil or bar, achieving better heat transfer and permitting cooler operation at a given output. Thermosetting insulation systems tolerate higher continuous operating temperatures than older systems with less mechanical deterioration.

f. *Short-Circuit Ratio*.

(1) The short-circuit ratio of a generator is the ratio of the field current required to produce rated open circuit stator 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.

(2) If not specified by the user, a short-circuit ratio of 0.8 is the minimum value per IEEE C50.12 standard requirements. A system stability study may be performed to determine if generators at the electrical location of the plant are likely to experience instability problems during system disturbances. Appropriate short-circuit ratio values may then be determined from the model studies and specified.

g. *Synchronous Condensing Capacity*.

(1) A generator operating as a synchronous condenser allows the unit to operate online without any water flow and thus without generating real power. This can be advantageous as it allows the generator to provide voltage support to the system as well as the ability to quickly load up real power, at the cost of some amount of real power consumed to spin the unit.

(2) The ability to operate as a synchronous condenser may depend on turbine elevation relative to tailwater. Using compressed air to depress the water level in the draft tube can assist in condenser operation.

h. Power Factor.

(1) The heat generated within a machine is primarily a function of its kVA output and field current excitation. The nameplate kilowatt rating of a generator is the kVA fshould be determined after considering the load and the characteristics of the system that will be supplied by the generator.

(2) The selected power factor at which a generator is specified is affected by the transmission system to which it is connected. The generator may be required to assist in transmission line voltage regulation or operate with reactive power reserves for voltage support. Reactive support to be provided by the generator varies based on transmission line lengths, nearby generation or loads, and capacitor or reactor banks, among other possible considerations.

(3) The generator should be designed for the power factor at which it will operate. In general, unless studies indicate otherwise, the power factor selected should be 0.95 for medium and large generators.

(4) For generator refurbishments, nameplate power factor ratings of equipment are only rarely changed. If a generator uprate is being considered, increasing the nominal power factor may be considered to respect field winding thermal capability while allowing a stator winding rating increase. Any changes to nominal power factor ratings should consider transmission system requirements and impacts to voltage support capability.

i. Reactances.

(1) The 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 textbooks, system stability textbooks, and industry standards (for example, IEEE 115).

(2) Rated voltage values of transient and sub-transient reactances are used in computations for determining momentary rating and interrupting ratings of circuit breakers. A low 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 the reactances 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) Average values of standard reactance are probably 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.

j. Efficiencies. When procuring a new unit, 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 that 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. 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. For a generator of any given speed and power factor rating, design efficiencies are reduced by the following:

(1) Higher short-circuit ratio.

(2) Higher flywheel effect (Wk^2).

(3) Above-normal thrust.

k. Generator Neutral Grounding. Grounding the neutral points of synchronous generators limits overvoltages under phase-to-ground fault conditions and permits the application of suitable ground fault relaying. Suitable neutral grounding equipment should be provided for each generator in hydroelectric power plants. Details of generator neutral grounding are covered in depth in Chapter 9.

l. Generator Surge Protection.

(1) 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 because the relative cost of procuring and replacing (or repairing) the stator winding, suitable surge protection equipment should be provided for each generator. This is especially important for multi-turn, coil-type windings, as voltage surges can place severe stress on the turn insulation within the coils.

(2) 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. Details of surge suppression are covered in depth in Chapter 9.

6–3. Generator Stator

a. Stator Foundation.

(1) Stator foundations support the stator frame and are designed to transmit gravity loads to the powerhouse structure, to dampen vibration, to allow the stator to accommodate normal radial forces due to thermal expansion and contraction while resisting translation, and to allow the generator to withstand “generator upset” conditions with minimal damage.

(2) Typically, each stator foundation consists of a steel foundation (or sole plate), foundation anchors, radial dowels, foundation bolts or “hold down” bolts, and (frequently) jack screws. The exact component details and naming conventions vary depending on the design and the generator supplier’s naming conventions, but all types of generators are designed to withstand radial forces from thermal cycles and tangential forces from the generator’s operation. Since machine designs vary, it is important to understand how each component of this restraint system is intended to meet the original design parameters when operating and maintaining the unit and when considering changes to the design.

(3) The steel foundation and foundation anchors are set into a recessed “pocket” in the reinforced concrete structure. The foundation anchors are sleeved inside steel pipes and are developed into the reinforced concrete structure where the anchors terminate with an embedment plate and an anchor nut. The steel foundations are set and leveled

in the recessed pocket to match the stator frame. Grout is placed to fill the pocket and provide even bearing contact under the steel foundation and reduce vibration. Grout is not placed inside the foundation anchor pipe sleeves. After grout placement is complete, the foundation anchor nuts are torqued to clamp the steel foundations and grout to the supporting reinforced concrete structure.

(4) The stator frame bears directly on the steel foundations and is secured to the foundations with a system of radial dowels and bolts or “hold down” bolts. Older designs and smaller generators may have their frames secured to the steel foundations using bolts tightened to high torque levels. Larger and newer designs may have their frames secured to the steel foundations with hold down bolts or nuts tightened to lower bolt torque levels or even provided with a nominal clearance. Hold down bolts and nuts prevent the stator from moving upward, locking the stator against the radial dowels and preventing it from rolling over the radial dowels.

(5) Radial dowels are arranged radially to the center of the unit or slightly off radial at a 90-degree angle to the stator foundation. Each dowel is fitted into a horizontal hole that is bored between the steel foundation and the stator frame. The primary purpose of the radial dowels is to provide a large bearing surface against which the tangential translation or “spinning” force of the stator frame is resisted. When used in combination with hold down bolts or nuts, the radial dowels can also allow the stator to freely expand and contract along the radial dowels while still preventing the stator from tangential translation or spinning.

(6) When configured in this manner, radial dowels and hold down bolts act to release some of the radial stresses associated with normal operating cycles of thermal expansion and contraction keeping stator stresses lower, keeping the stator frame properly held and positioned, and limiting the amount of radial and tangential forces being transmitted to the reinforced concrete structure.

(7) Jack screws are also located on the stator foundations and are typically used to adjust the final position of the stator segments when the machine is assembled. Jack screws can be retained and set to limit the outward or inward movement of the stator, which can limit the tendency of the stator shape to deviate from circular over time.

(8) For restraint systems designed to release radial stresses, assuring that the system of restraints is functioning properly is key to the long-term health of the generating unit. Additionally:

(a) The contact surface between the stator and the steel foundation should be smooth, level, and free of defects. A dry lubricant such as molykote is often provided to reduce friction resistance on this contact surface as well as the radial dowel.

(b) The radial dowel should be free to allow slip. Means taken to prevent radial dowels from backing out are recommended but should not bond the stator frame to the steel foundation.

(c) Hold down bolts and nuts should be tightened enough to prevent them from loosening without being over-tightened and clamping the radial dowel to the stator frame and steel foundation. For machines where the hold-down nuts are the second uppermost nut on the foundation anchors, it is critical to assure that the lower foundation nut is fully torqued to the value needed to clamp the steel foundation to the concrete structure and that the upper hold-down nut is only lightly torqued for hold-down function.

(d) Jack screws (if present) are intended as an upper limit to stator thermal expansion and should not be tight against the stator when the unit is cool.

(9) Damage to the foundations can result if a generating unit experiences a fault, an out-of-phase synchronization, severe vibration, or seizing of the radial dowel function. Detailed inspection and evaluation are recommended following a severe fault or out-of-synchronous event and if unit has experienced severe sustained vibrations or if foundation grout is severely cracked and spalling.

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 laminations in the correct core geometry. Strength is needed for the core to resist deformation under fault conditions and system disturbances.

(2) Also, the core is subjected to magnetic forces that tend to deform it as the rotor field rotates. In a few large machines, this deformation has been known to cause the core to contact the rotor during operation.

(3) In refurbishments, the stator frame is nearly always re-used, with additional strengthening added if needed based on analysis of mechanical stresses for the refurbished and possibly uprated generator.

c. Stator Core.

(1) The primary component of the stator core is the thin sheet-steel laminations that, when stacked together and clamped, form the stator core. The stamping shapes are designed such that, when they are correctly stacked, they form stator winding coil slots with no stamping protruding into the slot. Uneven slots may result in the wear of winding ground wall insulation (and semi-conductive coating), preventing adequate tightening of coil in the slot, and, in extreme cases, erosion of the ground wall insulation.

(2) Stator cores are originally designed for a specific number of slots for the generator winding, depending on the overall winding design and various specification requirements. During generator refurbishments, it is often possible to re-use an existing stator core, though the following conditions may preclude the possibility:

(a) Poor stator core condition (damage due to fretting or failures, significant out-of-round condition, degradation at stator core splits, age, or service conditions-related deterioration (corrosion, brittleness, etc.).

(b) Generator uprate requiring stator core re-design or size increase.

(c) Generator winding reconfiguration (such as in some cases of changing from coils to bars or addressing end-winding vibration or core resonant frequency problems).

(3) When evaluating the re-use of a stator core, and after installation of a new core, a rated flux test (or core loop test) is performed to confirm integrity of the core lamination insulation. This test excites the stator core with approximately rated operating alternating flux by using cables wrapped around the toroidal form of the core. In locations where stator lamination insulation is insufficient or damaged, flux flows axially between laminations, which may result in a local hot spot. Multiple iterations of testing and repair may be needed before the core may be deemed acceptable for re-use.

(4) *Out of Round Stator Core*.

(a) A stator core that is not perfectly circular results in a varying air gap between the stator and rotor. Some amount of air gap variation is allowable, within industry standards and specification requirements.

(b) In machines where split-phase currents are monitored for machine protection, a variation in air gap causes a corresponding variation in the split phase currents. If the variations are significant, the machine trips by differential relay action, or the differential relays need to be desensitized to prevent tripping.

(c) A machine operating with a varying air gap may also result in additional vibration in the stator as well as higher pole face losses.

(d) Air gap monitoring systems may be installed to monitor the air gap variation over time. Refer to Chapter 28 for more detail on these systems.

(5) *Shipping and Assembly*. Stator assembly methods for new units typically differ from methods used for units to be refurbished:

(a) For new units, small stator assemblies that can be shipped in one or two pieces should be assembled as completely as possible at the factory, with final assembly on site. If the stator frame assembly must be shipped in more than two pieces, the core and winding are typically installed in each frame segment at the factory, with final assembly and winding completion on site. The practice of shipping complete portions of the stator for final assembly results in splits in the stator core, which is generally not preferrable. Field stacking of the stator core results in a higher initial cost for the generator but may provide better service life and reliability.

(b) For machines to be refurbished, very small machines may be shipped to the factory with the stator fully assembled, allowing all core and winding replacement to occur there prior to shipping back to site. Most machines, however, are refurbished on site. In cases where the stator core is to be replaced during refurbishment, continuous stacking of stator laminations to avoid core splits is the best practice. This provides additional stiffness of the core and prevents movement issues at the splits.

d. *Stator Winding Configurations*.

(1) *Multiturn Coil Stator Windings*.

(a) On smaller generators, and on certain sizes of larger machines, stator windings employing multiple turn coils are used. This effectively provides more coils per armature slot, giving a higher generated voltage per slot compared with a single-turn bar winding. With this winding design, the stator winding is divided into two or more parallel circuits per phase.

(b) On the neutral ends of the winding, one half (or as close to half as is possible in the case of windings with an odd number of parallel circuits per phase) of the parallel circuits in each phase is connected to the neutral point through a current transformer (CT) of carefully selected ratio and characteristics. On the generator output, another CT measures the total phase current. Differential relays compare the split phase current and total phase current to detect an internal generator fault. When connected in this way, the relays are also able to detect turn faults within individual coils.

(2) *Roebel Bar Stator Windings*. For large generators, winding designs using single-turn coils are preferred, in which case the neutral terminals are not divided. The single-turn bars use a Roebel transposition, rather than inverted turns or external strand transpositions, to balance current in the conductors. This type of winding 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 transpositions for all the strands. There are also certain configurations of large machines that do not allow the use of single-turn coils.

(3) When a generator is being rewound, it may be possible to convert from a multi-turn coil winding to a Roebel bar winding. In addition to removing the possible failure point of the turn insulation, Roebel bars are easier to replace in case of failure than coils are. In considering this option, assessing the winding configuration and number of slots is important to check feasibility, assuming the core is to be retained. Core height and the resultant number of parallel circuits per phase should also be considered.

e. Stator Winding Installation and Materials.

(1) The stator coils or bars are installed within the slots of the stator core, along with a variety of other materials to tightly pack the winding in the slots and ensure integrity of the external semi-conductive coating of the bar. Tightly packing the coils or bars in the slots prevents damage to the exterior surface due to movement, while also ensuring solid contact with the stator core to prevent external discharge between the winding surface and the grounded stator core.

(2) *Slot Fillers*.

(a) Fillers are installed at the bottom of the slot. These should be semi-conductive to allow adequate surface conductivity and grounding the external coil or bar surface to the stator core.

(b) Center fillers are installed between bars or coils within the slot to allow adequate clearance in the end winding and at the slot exit for installation. Stator resistance temperature devices (RTDs) are most typically installed within center fillers in designated slots to allow monitoring of winding temperatures.

(c) Side packing serves the purpose of maintaining tight packing of the stator winding, and there are different types of side packing systems (side ripple springs, conductive room temperature vulcanization (RTV) coatings, etc.).

(d) Top fillers are installed on the stator bore end of the slot to fill the remaining space before wedging the coils or bars into place.

(3) Modern wedging systems for hydroelectric machines generally include ripple springs, which are compressed to generally between 60 percent and 90 percent at the time of installation and wedging. These ensure positive pressure on the slot contents, holding the coils or bars in place even as materials may settle or shrink to some extent due to any final curing. The force exerted should be sufficient to resist movement of the stator coils or bars during a worst-case generator fault.

(4) Wedges are installed over the ripple springs, are designed to fit the slot wedge grooves, and provide final compression of the ripple springs. Typically, two to three wedges in each slot should be provided with small holes drilled in the face that allow using a depth gauge to measure the compression of the ripple springs beneath. Finally, the top and bottom wedges must be locked into place to prevent migration out of the slot in some fashion. Applying a permanent adhesive such as epoxy to all wedges is generally not advisable, as it can cause great difficulty later in case a repair or refurbishment is necessary.

(5) Coils or bars should be installed such that they are well centered axially in the slots and their ends are well aligned for connections to be made, with adequate spacing

between coils and bars at the slot exit. Manufacturers may have different practices for achieving this alignment, and processes should be followed consistently to ensure successful installation. Series connections, pole group jumpers, and circuit tap connections are made using suitable brazing methods, balancing ease of use and minimizing risk of damage to nearby insulation. The brazing process should be tested on sample pieces prior to brazing the winding to ensure a successful approach is used.

6–4. Rotor and Shaft

a. Rotor Assembly.

(1) Large generator rotors must be assembled in the powerhouse due to shipping considerations. Historic manufacturing methods have been one of two types, one in which the hub and arms are made of cast steel, the other with a cast or fabricated hub to which the fabricated rotor arms are bolted and keyed. 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. Modern generator hub designs should use forgings in regions of higher localized stress.

(2) For in-service fabricated rotor arms in particular, cracks have been found in overly constrained welds at the corners of built-up webs and flanges at the center hub; many designs avoid this high-stress concentration by rounding those corners. Note that the highest stresses in a rotor might occur when the rotor is simply supporting its own stationary weight, rather than when it is spinning, perhaps even in overspeed. This is a consideration for increased stops and starts of units, as well as for possible weld repairs.

(3) If a weld repair is done on a rotor spider, consider performing the repair outside the generator, such that grinding does not release ferrous particles within the generator, and to allow support of the rotor rim and poles if they are not removed. Additionally, relaxing the static load on the welds prior to performing the repairs is recommended.

(4) Rotor rims are made from built up sheet-steel punchings that are vertically keyed to the ends of the rotor arms and rest on a horizontal rim support at the bottom of the rotor spider arms. Rim support ledges might extend between arms in a full circle and serve to support the bolted-on brake ring. The rim has “torque keys” between the ends of the rotor arms and the stack of rim punchings and might also have “shrink keys” at this location. Some designs include a tight fit between the rim and rotor spider (“shrunk rim”), and some do not (“floating rim”). This fit between the rim and rotor spider can affect rotor spider stresses as well as potential fretting locations and relative difficulty of disassembly.

(5) Pole pieces, assembled and wound in the factory, are usually made of laminations pressed together and bolted or riveted into a single mass. They include 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. During original design and during refurbishment efforts, especially involving an uprate, the stresses in the rotor pole dovetail and rim slot should be considered. This can be a fatigue failure point depending on the design and stresses involved.

b. Field Winding.

(1) The field winding of salient pole machines is generally made of copper conductors that are wrapped in some fashion around the pole pieces. These conductors have insulation between each turn around the pole piece, as well as insulation between the conductor itself and the pole body. The conductive coils of each pole are then connected between poles using interpole connectors, which may be constructed in several different ways (typically either brazed flexible copper leaves or bolted flexible links).

(2) The conductor dimensions, generator thermal design, and field winding insulation temperature class primarily drive the capacity of the field winding. Field winding conductors are typically rectangular copper strips (“strip-on-edge”), though some machines may use copper wire wound around the poles. Due to ampacity requirements and the high distorting forces present on large machines with large diameters, the copper strip construction method is most used. Historically, field windings have been designed and constructed using Class 130 (B) insulating materials, but modern insulation systems for field windings are typically Class 155 (F). During special field testing following initial construction or major refurbishing, the temperature rise of the field winding is typically measured to determine the maximum allowable continuous field current for the winding.

(3) During design for generator refurbishments, it is necessary to determine a prudent scope of work for the field winding. In cases where a generator uprate necessitates a full refurbishment of the field winding due to temperature rise, the decision is readily made. In cases where the field winding and insulation system are adequately rated for the future conditions, the decision can be less straightforward:

(a) Failures of turn insulation are not typically an issue that merits a forced outage, though failure of the field pole ground insulation certainly results in a forced outage until the failed pole can be refurbished. Insulation condition assessment results may justify the complete refurbishment of the entire field winding (all rotor poles), but in most cases, the cost of performing this work is not justified by the low risk of relatively short duration forced outages.

(b) A full refurbishment of the field winding involves entire replacement of the conductors for wire-wound field poles, as opposed to only re-insulation for strip-on-edge-type windings.

c. Amortisseur Windings.

(1) Amortisseur windings (also referred to as damper windings) are essentially a short-circuited grid of copper conductors in the face of each of the salient poles on a hydroelectric 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 pole metal. In the second, the pole face windings are intentionally connected at the top and bottom of each pole to the adjacent pole’s amortisseur windings.

(2) While the generator phase currents are balanced and the generator is operating in exact synchronism with the power system, there is no current in the amortisseur winding and it essentially has no effect on the generator operation. If there is a small disturbance in the power system and the frequency changes slightly, the rotor speed and the rotating magnetic field speed will be slightly different. The rotor mass is

perturbed when synchronizing torque pulls 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. 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) 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.

(5) Connected amortisseur windings are of particular importance for motor-generators, especially those that may be started by direct connection to the transmission system. In such instances, significant current flows in the amortisseur winding, which can quickly cause severe overheating if the winding is not adequately designed and is not of the connected type. Motor-generators are often started by using another unit connected at the terminals to allow both units to accelerate simultaneously, reducing heating impacts to the amortisseur winding. A static frequency converter (SFC) or variable-frequency drive (VFD) may also be used for motor-generator startup.

(6) The amortisseur winding is especially important to systems that tend toward instability (systems with large loads distant from generation resources), and that may commonly operate islanded from the larger power system. The amortisseur winding also aids in reducing generator voltage on un-faulted phases under some fault conditions. It does this by contributing to the reduction of the ratio of sub-transient quadrature reactance and direct axis reactance, Xq"/Xd". 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.

(7) When generator rehabilitation is being designed, assess the existing amortisseur winding to confirm integrity. Brazed connections between the bars in the face of the pole and the shorting bars can fail, as can the interpole amortisseur connections. Mechanical and electrical wear can also occur between the amortisseur bars and the slot in the pole face, which can result in the bars breaking and ejecting from the pole face. Detailed inspections prior to solicitation, as possible, can assist in finding these problems and appropriately specifying work to perform.

d. Generator Shafts.

(1) Generator shafts with a 12-in (30.5-cm). 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 concentric oil pipes to the blade servomotor 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.

6–5. Mechanical Characteristics

a. Speed.

(1) Hydraulic requirements for the turbine design fix the speed of the unit within rather narrow limits.

(2) Generators below 360 revolutions per minute (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. Note that “overspeed” can refer to any speed above the nominal revolutions per minute (RPM) rating, whereas “runaway” means the unit speed is not being controlled and could reach theoretical maximum speed depending on gate opening, friction, and windage. Unit overspeed on loss of load, for example, is limited by wicket gate closure timing, and will not reach runaway speed.

(3) For adjustable blade (Kaplan) units, highest runaway speeds are reached when blades are at a shallow angle, meaning closest to horizontal (or “flat”). Kaplan turbines, or fixed-blade propeller units with very shallow blade angles, can have very high overspeed capabilities, 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. Provisions for ensuring blades pitch steep on loss of governor pressure should be part of the runner design requirements. Minimum blade angles can also be considered to reduce maximum runaway speeds.

(4) Generators for projects with Kaplan turbines have been designed for runaway speeds of 87.5 percent of the theoretical maximum turbine speed. The stresses during design runaway speeds should not exceed two-thirds of the yield point for the affected components. 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.

(5) 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.

b. Flywheel Effect.

(1) The 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 Wk² for speed regulation. As Wk² 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 Wk² must be provided to prevent hunting (sustained speed or power oscillations) 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:

$$H = \frac{kW \cdot s}{kVA} = \frac{0.231\,(Wk^2)(r/min)^2 \times 10^{-6}}{kVA} \qquad \text{Equation 6–1}$$

(3) The inertia constant ranges from 2 to 4 for relatively slow-speed (under 200 r/min) water wheel generators. Note that increases in a generator's ratings after an uprate decreases the inertia constant but not the actual inertia supplied to the power system. Transient hydraulic studies of system requirements furnish the best information about the optimum inertia constant, but if data from studies are not available, the necessary Wk² can be computed or may be estimated from a knowledge of the behavior of other units on the system. Increased Wk² proportionally increases generator base costs.

(4) The amount of Wk² 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 Wk² to provide satisfactory speed regulation. The starting of large motors on such systems should not cause a large drop in the isolated system frequency.

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

$$\text{Flywheel Constant} = \frac{(Wk^2)\,(r/min)^2}{hp} \qquad \text{Equation 6–2}$$

(6) If the hp in this formula is the value corresponding to the kVA (at unity PF) 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. *Motor-Generators*. Generators that operate as motors, such as pump turbines, have full load reversals, which has material life implications. Allowable mechanical stresses should be reduced to ensure full design life achievement. Fatigue analysis may be necessary. Components of particular concern are the rotor spider, rotor pole-to-rim connections, coupling bolts, shafting, and all rotating mechanical components.

6–6. Turbine Considerations

a. Because generator requirements depend in part on turbine characteristics, for new powerhouses or major rehabilitations, preliminary design work for the turbines generally begins prior to preparation of generator specifications. This permits the required turbine data for the generator specification to be obtained from the turbine specification, the turbine bid data, and the turbine model test. Pre-advertising correspondence with turbine and generator suppliers should provide verification that the turbine-related stipulations in the generator specification are practicable.

b. The required Wk^2 of rotating generator parts must be computed based on all related factors. This includes turbine characteristics as well as penstock, generator, governor, and power system characteristics. Maximum speed rise and pressure rise on loss of generator load are normally the critical mechanical factors.

c. Turbines and generators are specified to withstand stresses due to runaway speeds; however, the damaging effects of vibrations are indeterminate and require conservative limits on speed rise. Maximum speed rise should normally be limited to 40 percent above synchronous speed when the required Wk^2 can be obtained with a normal generator design. When the 40 percent limitation requires a special generator rotor rim design or separate flywheel, a greater allowable speed rise may be warranted but should not exceed 60 percent in any case. Maximum pressure rise at the turbine is usually limited to 30 percent above the maximum static pressure.

6–7. Generator Fire Protection

See Chapter 21 for specific requirements for fire protection systems.

6–8. Shaft Current and Bearing Insulation

Dissymmetry in the generator magnetic circuit can cause voltage to be developed on the shaft. If an electrical circuit is formed that allows current to flow through generator stationary components (bearings, bearing supports, piping, ladders, and handrails) it can cause damage. The shaft should be specified to include single or double insulation to all potential contact points at and above the rotor, and the shaft should be grounded below the rotor using a grounding brush. Bearings are especially vulnerable to shaft currents because the soft babbitt can be easily damaged.

6–9. Handling Provisions

a. *Powerhouse Cranes*. Powerhouse cranes are used to handle the generator parts and disassembly of the generating units. If feasible, cranes should be constructed or uprated so as not to be the constraining factor on generator size or weight. Exceptions to this policy may be required where a new unit is being provided in an existing crane-equipped powerhouse, or where overall program management requires a crane to be under contract before a generator contract is awarded. In these cases, the appropriate crane-imposed constraints should be included in the generator specification. Crane design guidance is covered in Chapter 20 of this manual.

b. *Weights and Dimensions*.

(1) Monitor manufacturer design submittals for generator weight and dimensions, both width and height, to confirm that the generator can be handled by the powerhouse crane with the existing powerhouse and units. Speed, Wk^2, short-circuit ratio, reactance,

and overspeed are the usual factors that have the greatest effect on weight variation. Where a high-value Wk^2 is required, a machine of a larger frame size with consequent increase in diameter may be considered. In this case, confirm the generator remains within powerhouse crane rating and coverage/clearances.

(2) Also monitor dimensions of the rotor and the method of assembling the rotor and the shaft in the generator to ensure they can be handled by the powerhouse crane with the existing clearances in the powerhouse.

c. Lifting Devices. The generator and other major components of the generator require custom designed lifting devices to allow the crane to be connected to pick the equipment. These devices were typically provided by the original generator manufacturer. See Chapter 20 for additional lifting device requirements.

d. Equipment Clearances During Lifting. Configuration of the powerhouse may require special handling considerations when removing a generator rotor from a unit. Original powerhouse construction documents typically included crane coverage and equipment handling diagrams showing crane positioning for moving generator components around the powerhouse. Changes to equipment sizes during rehabilitations could affect the handling clearances and should be verified prior to completing a design. Generator rehabilitation design packages should include these diagrams as reference drawings.

e. Rotor Pedestal.

(1) The powerhouse erection bay typically has an area that has been structurally reinforced to support the weight of a rotor and has provisions to secure the rotor. The rotor pedestal may consist of a reinforced pad or may also include additional steel weldments to support the rotor. When designing a generator refurbishment project involving multiple units, it may be necessary to consider adding a second rotor pedestal to support the desired refurbishment schedule.

(2) If the design of the rotor and shaft provides a permanent connection between the shaft and rotor hub, the rotor erection pedestal or support plate may be recessed into the floor or located on the floor below the erection bay to accommodate the length of the shaft. Holes in the erection bay or a floor recess allow reduced 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.

6–10. Generator Cooling

a. Generator Losses. Losses in a generator appear as heat, which is dissipated through radiation and convection (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.

b. Equipment. Motor-generators may need additional equipment to ensure adequate cooling when the unit is operating as a motor and rotating in the direction opposite of that during generation.

c. Closed Cooling Systems. An enclosed air housing with a recirculated air cooling system with air/water heat exchangers should be provided. A closed cooling system provides multiple advantages versus an open system:

(1) Cooling the generator can be more easily controlled with a recirculated air system.

(2) Stator windings and ventilating slots in the stator core are kept cleaner due to reduced dust and debris. This reduces the rate of deterioration of the stator winding insulation system.

(3) An enclosed air housing provides a containment volume suitable for total flooding agent fire protection systems, and the recirculating effects within the housing aid in providing a uniform flooding agent concentration.

(4) The air housing attenuates generator noise.

(5) The heat gains to the powerhouse are reduced, which reduces the load on the powerhouse HVAC system.

d. Air Coolers. Recirculated air cooling systems use a series of heat exchangers to cool the air from the generator. The heat exchangers (often called “surface air coolers”) are typically mounted on the outside of the stator frame and cool the air as it exits the stator. Raw water from the river is used as the cooling fluid. The heat exchangers may be single or multiple pass, depending on cooling requirements and cooler design. Coolers should be designed with as many heat exchanger tubes in the air flow passage as practical to reduce water usage.

e. Heat Exchanger Types. Two main categories of heat exchangers are typically used for generator air coolers: finned tube and plate fin. Finned tube-type heat exchangers can be further broken down into two types: wound fin and extruded fin. Both types consist of an array of tubes connected by water boxes through which cooling water flows. Historically, USACE has not utilized plate fin coolers as much as finned tube coolers. The differences, advantages, and disadvantages between the three types of heat exchangers are:

(1) *Plate Fin*. Plate fin coolers consist of a stack of thin plates that have been punched to accommodate the tube array. The tubes are mechanically expanded into the fins to secure the fins and provide contact for heat transfer. Plate fin coolers tend to be the most energy dense and economical of the three types of coolers commonly used for surface air coolers. They also tend to have the shortest service life. Fretting corrosion where the tube is expanded into the fin is a common failure point, as is loss of mechanical expansion and contact between the fin and the tube.

(2) *Finned Tube – Wound Fins*. Wound fin coolers use a water tube to which a fin is continually wound on, under tension, to act as the heat transfer element. There are multiple shapes of wound fins that have advantages in surface area and durability. Additionally, wound fin tubes can be solder dipped to improve heat transfer and increase durability. Wound fin coolers are more economical than extruded fin-type coolers but are also less durable. Loss of fin contact to the water tube and fretting corrosion are common issues.

(3) *Finned Tube – Extruded Fin*. Extruded fin coolers utilize a double tube configuration with an outer tube from which integral, helical fins are continuously extruded. The inner tube is inserted into the outer tube and mechanically expanded to create a continuous bond between the two tubes. Finned tubes are typically the most

expensive of the three types of coolers used, but also tend to have the longest service life. The double tube design provides additional protection against leakage.

(4) *Air Cooler Materials*. The following materials are typically specified for air cooler construction. If specific water quality characteristics are present in the cooling water that have caused issues with the materials specified, other materials may be used:

(a) Water boxes (painted carbon steel or stainless steel).

(b) Water tubes (90/10 copper/nickel).

(c) Fins (aluminum or copper).

(d) Tube sheets (naval brass).

(5) *Design Pressure*. Air cooler design working pressures typically range from 50 psi (345 kPa) to 100 psi (689 kPa). Selected design pressure depends on the cooling water source: gravity from the forebay or pumped from the tailrace. Design pressure for gravity or spiral case cooling water sources should be based on maximum project pool level, plus a surge allowance. For systems with pumped cooling water supply, coolers should be rated for the pump shut-off head. Hydrostatic tests should be performed at pressures of 150 percent of rated pressure.

(6) *Design Temperature*. Design cooling water temperature should be the maximum temperature of the cooling water source, plus a contingency allowance. Note that historic documentation for design temperature may not align with current operating temperatures of the project. Water temperatures should be verified during design. Outlet air design temperatures should be coordinated with the generator design but is typically specified to be 40 °C (104 ºF).

(7) *Design Airflow Rate*. Airflow rate is a function of the generator fan design. If the air flow rate is unknown, it is possible to verify the air flow rate for an existing generator through field testing. When considering uprating cooling capacity, increasing air flow rate is not typical and may be difficult.

(8) *Design Water Flow Rate*. Water flow rates should be verified by using a flow meter before replacing or redesigning air coolers. For gravity-supplied systems, changing water flow rates may be difficult. Flow rates on pump-supplied systems may have more capacity to increase flow rate, but pipe velocities and pressure losses should be considered before making significant changes.

f. *Cooling Water*. The turbine spiral case is normally used as the cooling water source for projects with heads of up to 250 ft (76.2 m). Where project head exceeds approximately 250 ft (76.2 m), pumped systems using a tailwater source are preferred. See Chapter 24 for additional requirements and information for water source.

(1) *Cooling Water Piping*.

(a) Cooling water is supplied to the air coolers through a ring header and discharged through a separate ring header. Piping should be consistent with Chapter 22. The water supply line to the air coolers should be separate from the water line to the thrust-bearing cooler, which allows independent flow modulation and isolation between the two systems.

(b) 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 imposes negative pressures on the heat exchangers. See Chapter 27 for additional information. It is desirable to keep a full flow of water through the thrust bearing oil cooler whenever the unit is turning.

(c) Vent piping should be provided to connect to the high-point vent in each heat exchanger. An isolation valve should be provided at each heat exchanger to allow air to be bled. Routing of the piping should minimize the potential for leaks on top of the generator.

(2) *Cooling Water Valves*. Isolation valves should be provided for each cooler supply and discharge as well as the inlet and outlet of the headers. Modulation valves on each cooler are typically not required. A combination modulation/isolation valve should be provided on the supply header and can be used to control generator temperature. Valves should be consistent with Chapter 22.

(3) *Cooling Water Modulation*. Temperature modulation of the generator cooling water should be provided for units where there are seasonal changes in cooling water temperature. Additionally, modulating the cooling water flows to minimize variations in stator winding temperatures, such as keeping the winding warm between starts, can reduce winding aging. A low-flow bypass should be provided around the modulating valve to allow minimum flow for startup.

(4) *Floor Drains*. Adequate floor drains inside the air housing should be provided to remove any water that may condense on or leak from the coolers.

(5) *Flow Indicators*. Each cooling water supply line should have a flow indicator. The flow indicator should have an alarm contact for low flow. Flow meters may also be installed in addition to flow indicators.

g. *Heated Air*. 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 carbon dioxide (CO_2) being discharged into the plant. Water from the coolers may be used as a heat source in a heat pump type of heating system, but if water flow modulation is used, there may not be enough heat available during periods of light loading, or when the plant is shut down.

6–11. Brakes and Jacks

a. *Brakes*. Generators are equipped with brakes to stop the rotation of the unit. Some units are equipped with combination brake/jacks that can also be used to lift the unit for maintenance. The brake/jack assemblies are mounted below the generator, typically on the lower bearing bracket. The brake pads bear on a segmented ring that is bolted to the bottom of the generator rotor.

b. *Blocks*. Blocks should be provided to hold the rotor in the raised position without depending on the jacks.

c. *Brake Actuation*. The brakes are actuated by air, typically at nominal 100 psi (689 kPa) and often supplied by the powerhouse air system. See further discussion on air supply in Chapter 25. Generator braking schemes are specific to each generator. Brake actuation may be pulsed at intervals or continuously applied depending on the generator design. During normal operations, brakes are automatically controlled by the governor, typically activating once the unit has decelerated to between 10 percent and 50 percent of rated speed.

d. *Jack Actuation*. When combination brake/jacks are used as jacks, high-pressure hydraulic oil is substituted for air. Pressurized hydraulic oil is supplied by a pump, the design of which varies with unit size and project installation. Many large units have permanently connected, motor-operated jacking oil pumps. Medium-sized and smaller generators can be served with a portable motor-operated oil pump that can be shared between multiple units. Some small units may be jacked using manual pumps. Pumps should be provided with suitable oil supply and sump tanks so the jacking oil system is complete and independent of the station lubricating oil system.

e. *Jacking Height*. Required height for jacking varies by unit and typically is driven by the height needed to change a thrust bearing shoe. The typical lift distance is approximately 1 in (2.54 cm). Generators driven by Kaplan-type turbines may need up to 12 in (30.5 cm). to accommodate removal of the Kaplan oil piping. 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.

f. *Brake/Jack Assemblies*. The brake/jack assemblies typically consist of a cylinder or housing that is mounted to the bearing bracket, a movable piston, and a brake pad assembly mounted to the top of the piston. The pad assembly typically includes a pad holder and the friction material. When designing the rehabilitation of generating units, replacement of the brake pads and rehabilitation of the cylinders should be considered.

g. *Brake Pads*. Existing brake pads may contain asbestos fibers and should be tested for asbestos prior to beginning work on the brake system. For personnel safety, new brake pads should be asbestos-free. To protect the equipment, new brake pads should be made from a friction material that is non-metallic, non-abrasive, and non-corrosive. Introduction of any magnetic particles into a generator should be minimized because they can cause damage under the influence of the magnetic field when the generator is operating.

h. *Brake Dust*. For many units, starts and stops are much more frequent than originally intended due to changes in the power grid such as energy imbalance markets (EIM). The increase in start-stop cycles has the potential to increase the amount of brake dust generated. Activating the brakes at a lower speed can help reduce the brake dust generated.

i. *Brake Ring*.

(1) The brake ring consists of several segments that are typically bolted to the bottom of the generator rotor. Segments are typically directional in that they have chamfers and taper to ensure smooth brake actuation. For most designs, brake rings made of ASTM A36 or similar material are adequate. Brake rings are typically located radially by a “key,” tangentially by dowels, and to the bottom of the rotor by bolts. The bolts should be made in the United States, preferably Grade 5, and positively prevented from backing out, such as by “pant leg” washers.

(2) When determining the condition of used brake rings, take measurements with the ring bolted in place as segments may deform when unbolted. Visual and non-destructive techniques such as dye penetrant testing or magnetic particle testing can be used to investigate for cracking damage for existing brake ring segments. Dye penetrant testing is preferred if the rotor is still within the stator because magnetic particles can cause or exacerbate damage to stator insulation while the unit is operating.

6–12. Thrust Bearings

The thrust bearing in the generator is the most important bearing element in the generator-turbine assembly as it carries the weight of the rotating generator parts, the weight of the turbine shaft and turbine runner, and 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.

a. Thrust Bearing Types.

(1) The most-used types of thrust bearings are the spring bed type (thrust shoes sit on a bed of springs) and jack screw type (each thrust shoe sits on an individual pivot point). The spherical type of thrust bearing has not been used on any USACE generators.

(2) 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 pumping the oil through a heat exchanger mounted near the bearing.

(3) These various types of bearings are fully described in available texts, such as "Marks' Standard Handbook for Mechanical Engineers" (McGraw-Hill) and "Mechanical Engineers' Handbook" (Kent 1950).

b. Thrust Bearing Lubrication. The basic principle of operation of all thrust bearing types is lubrication in the hydrodynamic regime, with a wedge-shaped volume of oil between the rotating bearing plate and each of the babbitted stationary shoes. Hydrodynamic bearings require rotation to establish the oil wedge, with a transition to hydrodynamic conditions often around 30 percent synchronous speed. See EM 1110-2-1424 for more details on turbine oil used for this application, as well as required cleanliness levels, maintenance, and testing.

c. Thrust Bearing High-Pressure Lift System.

(1) *General*. The rotating parts on some machines are so heavy that when the machine is stationary for a few hours, the oil is squeezed out from between the bearing surfaces. In this case, it is necessary to provide a means to get oil between the babbitted surface and the bearing plate before the unit is started and up to hydrodynamic conditions. The high-pressure lift system (HPLS, also sometimes referred to as the high-pressure oil injection system or HPOIS) provides pressurized oil between the bearing shoes and the thrust runner so that there is an initial oil film on unit startup. The system typically consists of a pump that draws oil from the thrust sump/tub and distributes it to each thrust shoe through a series of pipes and hoses.

(2) *Generator Rating*. Generators rated above 10 megawatts (MW), and generators in unmanned plants, should be equipped with provisions for high-pressure lift systems, which automatically actuate just prior to and during machine startup, and when stopping the machine. HPLS systems should be added during unit rehabilitations unless there is documented justification not to.

(3) *Design*. Where an existing HPLS is being replaced in kind, the plans and specifications should provide a complete design. Where a HPLS is being added to a unit that does not currently have one, or if the unit weight is changing significantly, it may be prudent to use performance specifications for the HPLS and have the turbine/generator contractor complete the design.

(4) *Pump*. The pump used for the high-pressure lift system should be a fixed-flow rate, positive displacement type driven by an electric motor. Rotary screw, gear, or piston are acceptable pump types, depending on the required pressure. Pump pressure

and flow rate depends on the weight and size of the unit, and the size of the depressed area in the thrust shoe surfaces that are accessible to the pressurized oil, as well as the required amount of lift. Note that the required oil pressure is less than one would calculate using only the recessed area of the oil pockets, due to shoe deformation.

(5) *Filtration*. A filter on the discharge of the pump should be provided to prevent debris from being discharged into the thrust shoes. Strainers may be included on the suction side of the pump, but filters are not typically provided for the suction side of the pump due to potential oil starvation issues if the filters become clogged.

(6) *Tubing and Hose*. Tubing to distribute oil to each thrust shoe is typically made from stainless steel. Flexible hoses should be provided between the distribution tubing and the thrust shoe to accommodate any thrust shoe movement. Flexible hoses must be made of materials that are compatible with the turbine oil used at that specific Project. This includes the exterior surfaces of the hoses as they are immersed in oil. Improper material selection can lead to premature failure of the hoses. Tubing and hoses located above the rotor require electrical isolation to protect the thrust bearing from stray currents that can damage the soft babbitt.

(7) *Check Valves*. Check valves are installed at each thrust shoe to prevent backflow of oil from the shoe to the HPLS.

(8) *Orifice*. To ensure each thrust shoe receives an equal flow rate of oil, fixed orifices are installed at each shoe. Orifices are sized so that the pressure loss between the pump to each shoe is equal. Adjustable valves or orifices should not be used as it could lead to improper adjustment.

(9) *Pressure Relief*. The HPLS should include a pressure relief valve and circuit to prevent overpressure.

(10) *Control*. Control of the HPLS system should be integrated into the start-stop sequence of the unit so that the system is automatically run prior to starting a unit. The HPLS is typically configured to run for a set time or turn off once the unit reaches a preset speed. Pressure and/or flow switches should be installed to provide verification to the start-stop sequence that the system is working correctly. Alternatively, direct measurement of thrust bearing lift can be used to verify correct HPLS operation. The ability to manually start the HPLS should also be provided.

d. Thrust Bearing Oil Coolers. Thrust bearings are typically cooled by oil-to-water heat exchangers. There are two main types of thrust bearing oil coolers (TBOC): internal and external. Raw water is used as the cooling fluid.

(1) *Water Supply*. Raw water for the bearing coolers is typically drawn off the generator air cooler water supply line. Isolation valves should be provided for supply and discharge and should be in an accessible area. Active flow modulation is typically not needed, but any flow regulation should be done using the discharge side valves, not the supply side (see paragraph 24–4).

(2) *Internal Thrust Bearing Oil Coolers*. Internal TBOCs use a heat exchanger that is immersed in the thrust tub. Oil circulates over the heat exchanger through the mixing action of the thrust runner spinning in the tub. Internal coolers are the most common type and are the default choice when replacing existing coolers.

(a) Heat Exchanger Types. Finned, tube-type heat exchangers are the most common type used for internal TBOCs. The finned tubes are either curved to match the radius of the thrust tub or can be a series of straight tubes. Baffles may be installed to

create multiple passes. The other common types of heat exchanger include plain coiled tubing and shell and tube.

(b) Materials. Internal TBOCs are made from similar materials as the generator air coolers.

(3) *External Thrust Bearing Oil Coolers*. External TBOCs use a heat exchanger that is located outside of the thrust tub. Hot oil is pumped from the tub, through the heat exchanger and returned to the tub. External TBOCs are less common and are typically considered only in specific situations. They may be used when easier maintenance is required or if there are water quality issues with the materials commonly used with internal coolers.

(a) Design Considerations. When converting a unit that has internal coolers to external coolers, the design must be carefully considered. Existing coolers typically act as baffles, preventing centripetal forces of the spinning unit from pushing oil to the outer radius of the thrust tub. Additionally, the manner in which hot oil is pumped from the tub and cold oil is returned must be configured to ensure cold oil is reaching the shoes and that mixing is occurring throughout the tub. Oil spill prevention, keeping oil from moving into the raw water flow and out into the river, is a primary design concern for all oil coolers.

(b) Heat Exchanger Types. The preferred type of heat exchanger for external coolers is a plate heat exchanger. This type of heat exchanger provides excellent heat transfer capacity in a compact package. Plates can be configured in single wall or double wall designs. Double wall designs are used when environmental concerns are a priority. Stainless steel is the most common plate material. Plates can be sealed using gaskets or brazing. Gaskets allow easy disassembly of the plate stack but may create additional maintenance issues.

(c) Oil Pump. Oil pumps should be fixed-flow rate, positive displacement type, typically rotary screw or gear, and driven by an electric motor. One or two pumps per unit can be provided. Two pumps allow redundancy if one fails, but adds additional cost and maintenance requirements.

(d) Controls. Control of the external TBOC system should be integrated into the unit’s start-stop sequence. Pressure or flow switches should be included to verify proper operation of the system prior to unit startup. The control system should also allow the external TBOC system to continue running for a fixed time after the unit shuts down. This allows the system to continue to cool residual heat within the bearing.

6–13. Generator Guide Bearings

a. Generator guide bearings resist loads that could move the unit off its rotating centerline. All units must have at least one guide bearing. When the thrust bearing is above the rotor, a lower generator guide bearing is required. Two generator guide bearings should always be provided on generators with Kaplan turbines. The lower generator guide bearing is often referred to as the “lower guide bearing,” even though the turbine guide bearing is the lowest one.

b. Guide Bearing Types. Generator guide bearings tend to be pad-type configurations, although shell bearings have been used.

c. Guide Bearing Lubrication.

(1) Like the thrust bearing lubrication, guide bearing lubrication also operates in the hydrodynamic regime, with the spinning shaft “pumping” oil in a wedge shape between the shaft and each bearing shoe. Guide bearings typically have self-contained lubricating systems, employing grooved shoes to distribute oil from the reservoir into the shoe/journal interface. The bearing is typically immersed in a tub (or “pot”) of turbine oil. Many times, one of the generator guide bearings shares the tub with the thrust bearing.

(2) 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 lockable to minimize possibility of accidental draining of the oil during operation. See EM 1110-2-1424 for more details on turbine oil used for this application, as well as required cleanliness levels, maintenance, and testing.

d. Guide Bearing Cooling. Guide bearings may have passive cooling or may have active cooling that uses oil-to-water heat exchangers. Active cooling systems are similar to thrust bearing oil cooling systems. Oil spill prevention, keeping oil from moving into the raw water flow and out into the river, is a primary design concern for all oil coolers.

6–14. Temperature Devices

a. Resistance Temperature Detector Devices.

(1) RTD Leads. RTD leads are brought out to terminal blocks, which are usually mounted in the generator terminal cabinet on the generator air housing. Three-wire RTDs can compensate for the resistance of the RTD leads, assuming equal resistance for each lead. Four-wire RTDs can compensate for leads of different resistances, allowing for increased accuracy. For temperature monitoring purposes in hydroelectric units, three wire RTDs are typically recommended due to the lower cost and decreased terminal block space required. However, if sufficient terminal block space is available, four-wire RTDs may be preferred.

(2) Bearings. Bearings are equipped with embedded RTDs for local and remote temperature monitoring as well as over-temperature protection. Individual bearing segments (or shoes) may also have multiple RTDs within each segment. Oil temperatures in bearing tubs are also measured using RTDs. Modern instrumentation allows monitoring of some or all RTDs as desired.

(3) Windings. Generator stator windings usually have several RTDs per phase. On the larger machines, the normal practice has been to monitor two RTDs per phase and keep the remainder as spares. For windings with multiple parallel circuits in each phase, it may be preferred to install RTDs such that temperature for each circuit is measured. Additional considerations for generator stator temperature monitoring may be found in IEEE Standard C50.12.

(4) RTD Usage. How the RTDs are used depends partly on plant control system decisions. 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.

b. Air Temperature Indicators. Air temperature indicators in generator surface air cooler air streams are used to balance the cooling water flow, and to detect cooler problems. Air temperature alarms should be provided. Air temperature alarms or analog readings may also be provided as an input to the plant control system if the plant is automated. Air temperature alarms indicate the need for operator action, but alarm intervention procedures may vary between power plants.

c. *Bearing Temperature Alarm and Indication*. Temperature measurement devices with adjustable alarm contacts should be provided for bearing temperature indication. The temperature measurement indications are grouped on a panel, which can be part of the governor cabinet, mounted on the generator barrel, or on another panel where maintenance personnel or operators can easily see them. Alarm contacts are set a few degrees above the normal bearing operating temperatures to prevent nuisance alarms. Temperature indicator alarm points should be taken to the annunciator and to the RTU or plant control system.

d. *Bearing Temperature Trip Devices*. Temperature relays (device 38) should be provided to shut down the unit on high bearing temperatures, 105 °C (221 °F) or so. Note that once a bearing temperature reaches the trip point, the damage has been done and the bearing likely cannot be saved. Tripping the unit promptly is done to save damage to other parts of the unit resulting from failure of the bearing. It is not necessary to provide sequence of event recording for the device 38 because the bearing temperature event is such a slow process.

e. *Temperature Indication*. Historically, the temperature indication devices have been dial type, indicating capillary bulb thermometers with adjustable alarm contacts. 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. A separate temperature relay (device 38) should be provided for each bearing.

f. *RTD Elements*. Modern systems use RTDs connected to RTD control elements that allow alarm indication and trip functions. These control elements provide both the alarm indication and the temperature relay (device 38) functionality. Considerations should be made for control element action on loss of control power. Whether to alarm or trip on RTD temperature indication depends on other decisions about how the plant is 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.

6–15. Acceptance Tests

a. *General*. Because of the custom design of hydroelectric generators, it is advisable to perform a series of acceptance and performance tests on the generators during and following their field assembly, whether new of refurbished. These tests provide a quality control check of field assembly work, ensure that the units meet contractual performance guarantees, and provide a benchmark of “as-built” conditions to aid 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 (for example, tests for ensuring conformance with contractual guarantees).

b. *Field Quality Control Testing*. A series of dielectric and insulation tests for the stator and field windings are performed during field work. Tests include high-potential tests, surge tests, coil transposition group tests, and semiconducting slot coating-to-stator iron resistance tests. If the stator is wound in the field, a high-potential test is usually done once each day on all the bars or coils installed during that day. 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. The purpose of these tests is to confirm proper installation of the winding as it is incrementally assembled such that problems may be resolved with minimal rework.

c. *Final Acceptance Tests and Special Field Tests*.

(1) *Field Acceptance Tests* (*all units*). These tests consist of:

(a) Stator winding tests. These tests consist of insulation resistance and polarization index, corona probe, corona visibility (blackout), final AC high potential, partial discharge analysis (PDA) test, stator winding resistance and capacitance, DC ramped voltage, phase rotation, and noise measurement (except for refurbishments in which a new core was not provided).

(b) Rotor winding tests. These tests consist of insulation resistance and polarization index, voltage drop, AC high potential, and DC resistance testing.

(c) Ozone measurement.

(2) *Special Field Test* (*one unit of each type*). These tests consist of:

(a) Losses and efficiency tests.

(b) Heat run tests.

(c) Machine parameter tests.

(d) Overspeed tests (optional).

d. *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 requires 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 or rewinding. If possible and necessary, a second generator in the powerhouse should be made available to permit performing retardation (deceleration) testing to determine generator losses. The heat transfer method is an acceptable means of determining losses as well and does not require a second unit to drive the test unit.

(2) The manufacturer requires considerable advance notice of desirable testing dates to calibrate test instruments and ship necessary switchgear and 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 are 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 is not 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 CTs and potential transformers (PTs) if reliable data on plant instrument transformers are available.

(4) Specific details on test practices and procedures may be found in various industry standards (IEEE 4, IEEE 43, IEEE 95, and IEEE 115, among others). Specifications should consider the specific features of the generators and powerhouse when determining testing requirements.

Chapter 7
Governors

7–1. General

The primary function of the governor is to maintain the speed and power output of the turbine-generator by controlling the gate opening. For Kaplan units, the governor also controls the blade angle to optimize efficiency at varying heads and flow rates. The governor needs to be capable of controlling the speed of the unit both under normal operating conditions and during system disturbances to help stabilize the system frequency.

7–2. Governor Reference Documents

General guidance for design considerations and the preparation of contract specifications for the procurement of a governor system can be found in IEEE Standards 125 and 1207.

7–3. Design

The design of governors for turbines and pump-turbines is specified as a responsibility of the governor manufacturer. In general, the governor operating requirements and characteristics are determined from the electrical, mechanical, and hydraulic characteristics of the generator, turbine, and penstock.

7–4. Mechanical Considerations

a. Wicket Gate Closing Speed.

(1) Of particular importance is the maximum gate closing speed recommended by the turbine manufacturer; closing the wicket gates too fast can cause water hammer and closing them too slowly can cause high overspeeds. This gate-closing speed must not be changed without significant analysis.

(2) The design speed for wicket gate closure, and also opening, might be found in original O&M manuals or in original governor commissioning reports. It is good practice in any case to specifically measure the location of the stopping nuts that control maximum flow of pressurized oil to the closing side of the gate servomotor, prior to disassembly.

b. System Pressures.

(1) The nominal pressure of governor-servomotor systems is selected from a series of standard pressures typically ranging from 300–1,000 psi (2,067–6,890 kPa) for low-pressure systems. Turbine requirements will usually indicate the desirable nominal pressure (refer to Chapter 5). Where high-pressure oil systems are selected to be used or where an existing system is converted to a high-pressure oil system, the operating pressures can go up to 2,500 psi (17,225 kPa).

(2) Occasionally, the original design pressure may turn out to be insufficient to close wicket gates at high-head conditions, in which case the system’s design pressure may need to be raised by 10–20 percent. If design pressure is increased, particular attention must be given to the accumulator tank pressure rating and testing, with updated nameplate data if applicable.

(3) The governor pressure depends on the turbine, wicket gate, and servomotor design, so coordination is required between the governor and turbine contacts.

(4) The differential pressure across gate servomotor ports (and oil head ports of Kaplan units) is assumed at 80 percent of the minimum working pressure range for figuring servomotor capacity. This assumed value allows piping and valve losses and requires that the governor and turbine contractors cooperate to limit the pressure drop in the system accordingly.

(5) System design pressure should be at the pressure tank safety valve setting, which is normally 110 percent of nominal system pressure.

c. *Oil Heaters*.

(1) The minimum and maximum design ambient temperatures should be the heating and ventilating system design temperatures for the room with allowance for nonuniform temperature conditions in the room. The minimum ambient temperature stated may be of significance to the governor contractor in determining the need for oil heaters if oil of higher viscosity than standard turbine oil is used in the governor system.

(2) If oil heaters are used, take care to ensure that the surface temperature of the oil heater does not cause any chemical change of the oil, such as chemical breakdown. A general rule is to use heating surfaces under 11 watts per square inch. The best way to accomplish that is likely to be a space entirely separate from the oil, with heating elements in a separate enclosure at the bottom of the sump. Such an arrangement gives the additional benefit of natural convection to mix the oil.

(3) If that is not feasible, a dry well may be installed into the sump, but preferably with a kidney-loop filtration system as well, so that the oil is constantly in some motion, rather than remaining stationary at the warm surface, potentially heating to the point of oxidation.

d. *Pressure Tank*.

(1) *Location*. The powerhouse equipment layout should provide the pressure tank location(s) with the shortest and most direct lines practicable from the tank to the actuator and servomotors to minimize pressure losses.

(2) *Tank Design and Pressure*. The tank and safety valve must be designed according to the latest version of the ASME BPVC. Volumetric considerations are described in Chapter 25. The tank design pressure should be a minimum of 115 percent of the maximum system operating pressure. This allows variations in the pump stop switch, oil pump pressure relief valve, and safety valve blowdown pressure. A pilot-operated ASME safety valve should be used, which has a 98 percent cracking pressure and a 4 percent blowdown. The safety valve setting should never exceed the stamped tank pressure rating but should be equal to or less than the stamped tank pressure rating. Example as follows:

(a) Stamped Tank Pressure – 696 psi (4,795 kPa)

(b) Stamped Safety Valve Setting – 605 psi (4,168 kPa)

(c) Safety Valve Cracking Pressure – 593 psi (4,086 kPa)

(d) Safety Valve Blowdown Pressure – 580 psi (3,996 kPa)

(e) Oil Pump Pressure Relief Setting – 575 psi (3,962 kPa)

(f) Governor Oil Pump High-Pressure Stop Switch (Maximum system operating pressure) – 550 psi (3,790 kPa)

(3) *Tank Test Pressure*. Shop test pressure should be consistent with the ASME BPVC. This is typically 150 percent of the stamped tank pressure.

(4) *Tank Height*. A specification restriction on tank height should be avoided unless required by powerhouse structural configuration.

(5) *Tank Oil Level Alarms*. High and low oil level alarms are normally required to monitor pressure tank and sump tank oil level in the control room. In addition, sump tank low level contacts are used for pump control to stop the pump and in case of low sump oil level due to pump unloader valve failure, pressure switch failure, or a pressure tank air leak.

e. Distributing Valves.

(1) As stated above, the required setting for the wicket gate opening or closing rate depends on the design for maximum unit overspeed and the water hammer design stresses in the penstock and turbine. The timing usually stated in the specifications is between 8 and 20 seconds.

(2) Take care to note the source and whether it is specifying the complete closing time (100 percent open to 0 percent open), or the closing time from 75 percent open to 25 percent open (to avoid confusion over the change in speed with hydraulic cushioning at the extreme gate positions).

(3) For turbine blade adjustment, a rapid response is not required and can impose undesirable stresses in the blade operating mechanism. Blade timing is usually stated in the specification and is between 20 and 60 seconds.

(4) *Distributing Valve Rehabilitations*.

(a) When the governor is rehabilitated or during a conversion from mechanical to digital controls, the main body of the distributing valve is reused in most cases, possibly with a new gasket at the joint between the valve bottom and the floor of the control cabinet.

(b) Because a unit outage is required to disassemble the valve for inspection, at least one spare set of the distributing valve spool, bushing, plunger, and servomotor stem should be available for each type and “family” of distributing valve prior to on-site work. Depending on the schedule versus budget risks and priorities, the first valve set might be refurbished to become a spare before taking the next unit out of service and so on, finishing with a spare set.

(c) Additionally, an inspection of the distribution valve piping condition is typically performed during the outage, taking care not to introduce contaminants to the governor system.

f. Brake Air Valve. The air pressure for the brake air valve should normally be specified at a nominal 100 psi (689 kPa). If there is reason to expect the station service air will be controlled to a higher pressure, the powerhouse construction contract should require a pressure-reducing valve in the brake system air supply. If the turbine runner is below minimum tailwater elevation, a timer to effect intermittent operation of the brake air valve is seldom justified, as satisfactory operation is normally possible by allowing the unit to decrease to 30 percent speed with no brake application, then apply brakes continuously.

g. Governor Oil Pumps.

(1) There should be at least two governor oil pumps per generator. A third smaller pump should be considered when the two main pumps are large because large pumps

add significant load and voltage transients on the station service systems. A small DC pump should be considered to maintain pressure for black start units.

(2) Some high-pressure governors may use screw/auger pumps, but most use gear pumps such as the Woodward XX Herringbone pump. Inspection and rehabilitation of pumps should be considered when scoping major governor work. Typically, this includes, at a minimum, the replacement of bearings and seals and realignment.

(3) An unloader valve, check valve, and pressure relief valve should be provided for each pump.

7–5. Digital Control System

a. General.

(1) The original turbine-generator governor control systems were typically mechanical in nature. The mechanical controls use gears, pulleys, cables, mechanical linkages, counterweights, and cams to provide feedback and operated a pilot valve that controlled the distributing valves to adjust the position of the gates and blades. The mechanical type of controller is no longer available from the major manufacturers, although certain manufacturers may still offer mechanical spare parts for refurbishment.

(2) Modern governor controls are digital systems. They consist of a programmable controller, input and output (I/O) modules, and signal transducers to monitor and control the unit. The software program interprets the input signals and generates output signals to operate proportional valves that control the distributing valves. The control system can increase unit efficiency for Kaplan turbines by automatically adjusting the blade angles to varying head levels with a 3D cam table. A directional shutdown solenoid valve is used to move the gate distributing valve to the gate closed position in case of proportional valve failure.

(3) All new governor control systems furnished by equipment manufacturers are digital. When a mechanical governor is rehabilitated, it is typically converted to a digital control system, though a mechanical control system can be refurbished and retained if desired.

b. Hardware.

(1) *Control Cabinet*. The governor controller, I/O modules, power supplies, and a human-machine interface (HMI) are typically housed within a single control cabinet. The control cabinet is typically integrated into the actuator cabinet, or a stand-alone cabinet located adjacent to the actuator cabinet. The equipment should be protected from prolonged exposure to any oily environment, and as such, control cabinets are typically rated National Electrical Manufacturers Association (NEMA) 12. Additional ventilation may be required to maintain the ambient temperature within the cabinet below the operating temperature limits of the digital equipment.

(2) *Power Supplies*. Power supplies are required to provide a control power source for the transducers and electrically operated hydraulic valves; they can also provide power to the digital controller. Input source to the power supplies should come from the DC system for reliability. Output voltage of the power supplies is typically 24 volt direct current (VDC).

(3) *Controller and Input/Output*. Governor manufacturers may offer their own proprietary controller and I/O modules, but the general trend (and USACE preference) is to specify commercial off-the-shelf programmable logic controllers (PLCs) and I/O

equipment from the major PLC manufacturers. These PLCs offer the ability to modify the system using common hardware or software in lieu of having to issue sole-source contracts to the manufacturer for proprietary equipment and services.

(4) *Transducers*. A variety of transducers are required to provide the necessary feedback on the operating condition of the unit to the controller. The proximity probes, gate position transducers, and blade position transducers are powered from the 24VDC power and typically provide a 4-20 mA analog signal back to the PLC. The minimum required transducers include the following:

(a) Gate Position Transducer. Magnetostrictive linear displacement transducer (MLDT) installed on one of the gate servomotors to provide gate position feedback.

(b) Blade Angle Transducer (for Kaplan units). MLDT installed on the blade restoring cable or rotary transducer coupled to the mechanical blade angle indicator to provide blade angle position feedback.

(c) Watt Transducer. Uses the voltage and current signals from the unit's instrument transformers to provide feedback for the unit's power output.

(d) Frequency Transducer. Provides feedback on the operating speed of the unit based on the frequency of the output voltage of the unit as measured by the unit's PTs. Often this involves two devices: one to convert the 120VAC sinewave to a 24VDC square wave and one device to measure the time between square waves.

(5) *Backup Speed Sensing*. Provide backup feedback of unit speed by measuring the rotation of the shaft. The signal is also used to detect creep when the unit is not running. This can be performed by:

(a) Using proximity probes to detect/count the flyball gear teeth or a separately mounted speed disk attached to the shaft.

(b) Using magnetic sensors to detect the poles on multi-pole magnetic tape attached to the shaft.

(6) *Electro-Hydraulic Interface*. The electro-hydraulic interface (EHI) typically consists of a manifold with a manual 3-way valve, oil filters, gate shutdown solenoid valve, and proportional valve(s).

(a) The manual 3-way valve allows the operator to select between two oil filters. The filters, typically 5–10 microns, protect the electrically operated hydraulic valves from damage from contamination. Electrically operated hydraulic valves should be properly rated for the operating pressure of the governor. The valves are used to control the flow of oil to the gate and blade distributing valves.

(b) A shutdown solenoid valve is a two-position valve that, when the solenoid is de-energized, ports oil to move the gate distributing valve to the "close gates" position and disables the gate proportional valve. It is de-energized when the unit is shut down, when a lockout relay trips, or when the governor system fails. With the solenoid energized, the shutdown solenoid valve allows oil to flow to the proportional valve.

(c) The gate proportional valve controls the gates by porting oil to the gate distributing valves, which ports oil to the servos to adjust the gate position. For Kaplan units, the blade proportional valve controls the blades by porting oil to the blade distributing valve, which ports oil to the oil head to control the blades.

(7) *Distributing Valve Position Transducer*. A linear variable differential transformer (LVDT) provides feedback to the gate proportional valve.

(8) *Backup Overspeed Switch*. A backup overspeed switch that forces the unit to shut down in the event of an overspeed condition should be implemented. This can be done by using either (1) a mechanical speed switch or (2) an electrical speed-sensing system independent of the governor.

(9) *Human-Machine Interface*.

(a) Local control HMI for the governor is provided via a touchscreen monitor at the actuator cabinet or unit control board that communicates with the PLC via Ethernet. From the HMI, the operator can control the unit, monitor individual I/O points, monitor alarms, and adjust tunable variables.

(b) The minimum recommended size of the screen is 15 in (38.1 cm).

(c) Depending on the number of units and layout of the powerhouse, a central control HMI(s) may be installed in a central location (the control room). Operators can use the central HMI to control and monitor the digital governor systems for all the units.

(10) *Ethernet Switch*.

(a) A local Ethernet switch in the control cabinet is required for the communication between the governor PLC and local HMI. The Ethernet switch should have a minimum of two spare ports to connect a laptop for programming and for connection to the governor network.

(b) Where central control HMI(s) are installed in the control room, additional Ethernet switches are required for the central control HMI(s) to communicate with each of the unit governor PLCs.

(c) The Ethernet switches used in the control cabinet or as part of the governor network should be a managed switch to facilitate cyber security requirements.

(11) *Hardware Redundancy*.

(a) Programmable logic controllers and associated I/O modules have proven to be very reliable. Redundant PLCs and modules significantly increase cost and complexity and therefore are not recommended. Self-diagnostic capabilities of the PLC system help to identify failed components, and these components can be replaced quickly.

(b) A faulty signal from a non-redundant transducer could lead to erratic operation of the unit. Redundant transducers should be installed to allow simple and reliable transducer error detection in the PLC and allow the unit to continue running in the event of a transducer failure.

(c) Redundant power supplies should also be provided to ensure a power supply failure does not result in a unit shutdown.

(12) *Maintenance Laptop*. To facilitate maintenance of the governor PLC and HMIs, all required programming and configuration software packages for all the hardware (PLC, HMI, Ethernet switch, etc.), communications drivers, and license files should be pre-installed and tested on a laptop to be provided by the governor manufacturer. Backup copies of all the as-installed files, drawing files, and O&M manual can be installed on this laptop, but it is advisable to have an additional copy stored on a remote storage device.

c. *Software*. The governor control algorithm is implemented via software. The PLC programming software package is proprietary to the specific PLC manufacturer. The preferred programming language is ladder logic, however, any of the 5 programming languages under International Electrotechnical Commission (IEC) 61131-3 are acceptable. The governor manufacturer provides the programming for the different governor control modes.

(1) *Control Modes*.

(a) Speed Control. Governor adjusts the gate position based on the speed and droop setting using "speed droop," which is based on wicket gate position. This is a standard operating mode of the governor. Reference paragraph 4.5.1 of IEEE Standard 1207.

(b) Load Control. Governor adjusts the gate position based on the speed, power, and droop setting using "speed regulation," which is based on the power output. This should be a standard mode of the governor. This operation can also be referred to as "Power Control Mode" or "MW Control Mode." Reference paragraph 4.5.2 of IEEE Standard 1207.

(c) Flow Control. Governor maintains flow through the unit based on user selectable flow setpoint, typically as an add-on feature to Load Control. This control mode is typically only required for units where maintaining a constant flow of water through the unit is an operational requirement.

(d) Control Functions. Additional control functions can also be implemented into the controller. These functions are not required as part of the basic digital governor but can be implemented into the controller as part of the initial installation or later in the future.

(2) *Examples of Additional Control Functions*.

(a) Generator Starting and Stopping Sequencing. The control logic sequencing for operation of the unit auxiliaries has historically been implemented via hard-wired relays and timers in the unit control board. Incorporating this function into the controller eliminates many of those hard-wired devices. Regional preferences in USACE typically dictate whether starting and stopping sequencing is incorporated into the governor PLC, incorporated into a separate unit PLC, or left in a hard-wired relay/timer implementation.

(b) Governor Oil System. The governor oil pumps are typically controlled by a stand-alone, hard-wired control system to maintain the governor operating oil pressure. System pressure, pump status, and sump and pressure tank levels can be added to the governor controller for improved monitoring and alarming.

(c) Air Balancing. This function is typically manually performed by the plant staff at regular intervals. Incorporating this function into the governor controller automates the process, assures it is performed at the scheduled intervals, and eliminates the need for human intervention.

(d) Synchronous Condensing. For units that are used for condensing, the governor controller can be programmed to provide control of the water depression process.

(3) *Human-Machine Interface Software*. The governor HMI programming software is available from various HMI software developers. The HMI software provides the interface between the PLC and touchscreen display for control, monitoring, alarming, testing, modifying the tuning parameters (droop, proportional-integral-derivative (PID) gains, etc.) and can assist with troubleshooting. Selection of the software package often depends on the availability of communication drivers for the specific PLC and HMIs used and compatibility with existing HMI software already in use at the plant.

7–6. Testing and Performance

After the governor is fully installed, the performance of the governor should be tested to verify it complies with the performance requirements of the specifications. Testing should be conducted according to ASME PTC 29.

Chapter 8
Excitation Systems

8–1. General

a. Design Practice. Excitation systems should be designed considering generator, transmission system, operational, and maintenance aspects. Current standard practice in the design of USACE power plants is to use solid-state, static, bus-fed excitation systems for the generator exciter and voltage regulator function. Solid-state static excitation systems currently available from reputable manufacturers exhibit a more predictable and faster response than older rotating systems, while maintaining comparable, and often improved, reliability. All excitation systems cabinets should be designed for reduction of electromagnetic interference (EMI).

b. Brushless Systems. Rotating brushless excitation systems are considered in some cases when an excitation system replacement design is being developed. These systems are relatively new, and few manufacturers have experience at the time of this writing.

c. Excitation Systems. When specifying or designing excitation systems, multiple factors must be considered. These include ratings, physical size and location, performance requirements, equipment type, control and interfacing details, and testing and commissioning requirements. IEEE Standard 421.4 provides recommendations for preparing specifications for excitation systems.

8–2. Excitation System Types

a. Static Excitation Systems.

(1) Bus-fed, solid-state excitation systems are made of three general elements: the PPT, the rectifier bridge (or rectifier), and the control section (voltage regulator function). An example schematic is shown in Figure 8–1.

(2) The location of the PPT may depend on the supply source chosen. If power to the PPT is supplied from the generator leads, the cable or bus arrangement for supplying this power to the PPT must be considered in the design and layout of the system. The location of the PPT is generally determined such that it may be directly next to the exciter cabinets (in a “close-coupled” arrangement) allowing flexible links or rigid bus to connect between the PPT and the exciter internal bus. PPTs are typically self-cooled, and the designer should consider the ambient temperature and available space when determining PPT rating and temperature rise requirements.

(3) Ideally, the static excitation system cabinets are located with the PPT in a location that allows convenient routing of all conductors. Considerations include AC conductor routing to the high-voltage terminals of the PPT, connections of PPT low-voltage terminals to the exciter cabinets, exciter DC output leads to the generator slip rings, and control cable routing. Additionally, operator and electrician accessibility, seismic mounting, flooring finish work, and available space should be considered when determining equipment location.

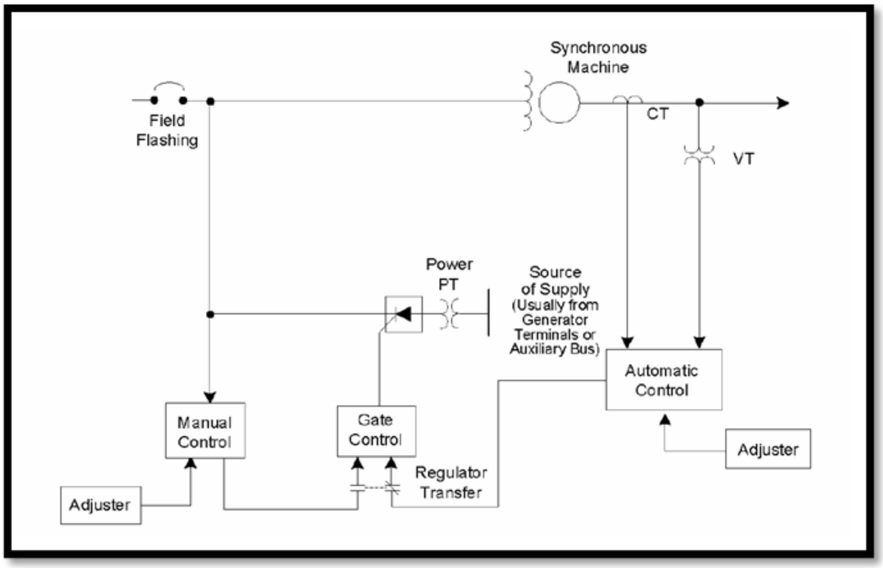


Figure 8–1. Static excitation system schematic (IEEE 421.1)

(4) Modern static excitation systems are generally constructed using a full-inverting rectifier bridge. The full-inverting exciter system uses six (or more) silicon-controlled rectifiers (SCRs) in the rectifier bridge. By this means, the generator field voltage can be forced either positive or negative. A full-inverting system can force the field voltage down as needed due to system events. It can also force generator voltage down if the machine is suddenly tripped offline while carrying a substantial load. In both cases, a full-inverting exciter reduces voltage stresses on the generator. In the first case, the full-inverting exciter also assists in maintaining system stability. Full-inverting systems are the industry and USACE standard at the time of this writing.

(5) Redundant bridges may be justifiable in cases where a generator unit outage is of high-potential impact. This could be due to high loss of generation, environmental impact, or limitations such as number of units and water flow requirements at the specific project. Bridges do not usually fail, so standard practice is to include only a single rectifier bridge.

(6) Static excitation systems permit a much faster response than rotating excitation systems due to the elimination of delays resulting from the inductances inherent in rotating machines. Due to this faster response, greater transient stability is achievable with a static excitation system.

(7) Transient reductions in output voltage can be minimized, and voltage recovery speed improved, with field forcing, which is high in magnitude and fast acting. Increasing the field ceiling voltage helps greatly in overcoming the delay in field current rise caused by the inductance of the generator field winding 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.

(8) PPT protection from overcurrent conditions should be provided by current limiting fuse (CLFs). The available fault current at the input to the PPT is quite large, so

it is 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 potentially damaging voltage transients. 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.

(9) 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 rectifier bridge input, at the generator field input, or at both places, including a means of dissipating energy stored in the field. 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.

(10) For field removal, there are generally two options available. One option involves using a DC field breaker located at the output of the rectifier bridge, known as a device 41 (field breaker). The second option is an AC breaker located at the input to the rectifier bridge, typically known as a device 52E (AC circuit breaker dedicated to excitation).

(11) Discharge of the energy stored within the field winding is performed using a thyristor-based element and a discharge resistor. A thyristor is a semiconductor device capable of switching to the conducting state within a very short time. The thyristor-based discharge element typically operates under two scenarios. It operates whenever the field excitation is removed via the opening of a device 41 or device 52E as previously described. The discharge element also operates when a field overvoltage (positive or negative) is detected. This circuit is commonly referred to as the “crowbar” circuit. Design considerations and descriptions of the various field discharge methods are described in IEEE Standard 421.6.

(12) 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 fans failing to start, air flow switches failing, fan air flow causing foreign material to be deposited on filters, and worn-out fan motors causing noise in the regulator control system. On large generators, it may not be practical to use a self-cooled system. Modern static excitation systems typically use fan cooling for the bridge(s).

(13) If the capability of connecting a unit to a de-energized transmission system is 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. The utility should be consulted to determine the voltage necessary for charging lines and transformers to re-energize a power system.

(14) The conductors supplying the DC field current from the exciter cubicles to the generator slip rings may be either cable or bus. Bus is generally preferred for longevity where the arrangement of equipment permits. Cable may be more practical in many cases, where complex concrete penetrations or long runs may be necessary. In any case, locations of junctions and disconnection points (bus splits) should be carefully

considered to facilitate generator disassembly. Cable is typically diesel locomotive (DLO)-type cable due to its high flexibility and ease of installation, as well as electrical properties.

b. *Rotating Excitation Systems*.

(1) Rotating excitation systems were historically the primary method of excitation used before reliable high-power semiconductors became prevalent. The information in this section is included for reference, but new systems of this type are not recommended. These systems use additional power sources (permanent magnet generator (PMG), rotating pilot exciter, etc.) to supply field current to the rotating DC exciter. The DC exciter then ultimately supplies DC current to the generator field winding.

(2) Due to the time delay (inductive circuit time constants) associated with the additional machine(s) involved in these systems, the terminal voltage response time is generally much slower than that seen with a static excitation system.

(3) Multiple arrangements have been utilized for hydroelectric generators. Figure 8–2 through Figure 8–4 from IEEE Standard 421.1 reflect three of the most common among USACE facilities. In the first, a rotating amplifier is supplied by automated control to adjust the field of the DC exciter. In the second, a motor/generator set (MOT and PMG) is used to supply excitation to the DC exciter. In both cases, a rheostat is available for adjustment to the DC exciter field. In the third, a rheostat is driven by automated controls, while contacts allow quickly lowering or raising the field to the DC exciter.

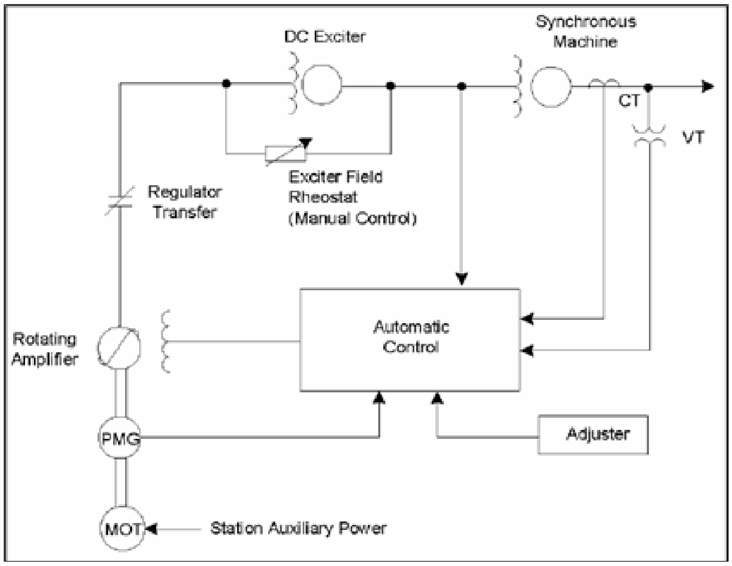


Figure 8–2. Direct current generator-commutator exciter with rotating amplifier

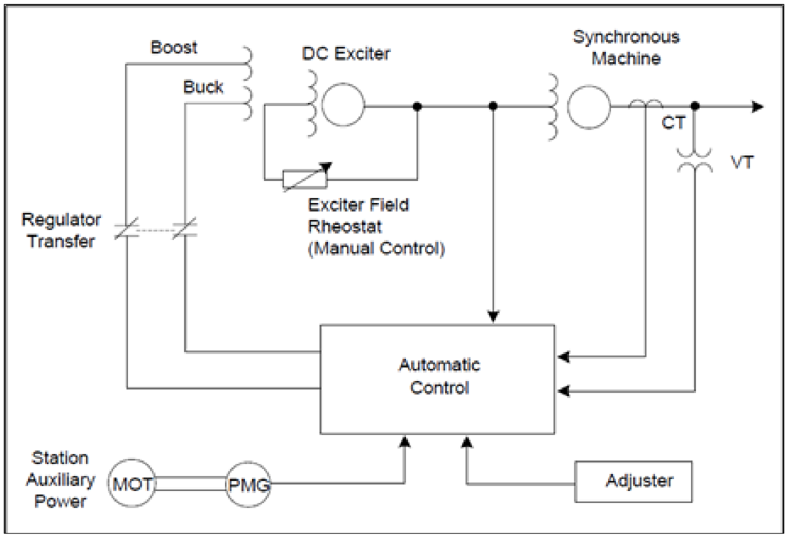


Figure 8–3. Direct current generator-commutator exciter with continuously acting regulator employing static amplifiers

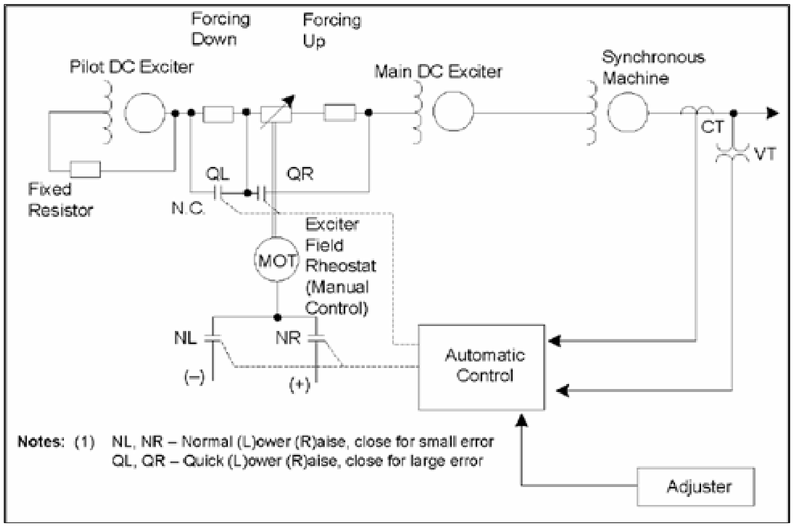


Figure 8–4. Direct current generator-commutator exciter separately excited with non-continuously acting rheostatic regulator

(4) Due to their analog nature, it is difficult to precisely define controls and responses of rotating exciters, and to precisely match response between otherwise identical units. Additionally, gradual changes of component characteristics over time can lead to less predictable response. Testing and modeling these systems according to NERC-MOD requirements is an effective means of tracking system response over time.

(5) Rotating excitation systems commonly feature additional windings to test and maintain. In addition, commutators add an additional maintenance item with wear, component replacement, and carbon dust contamination. The maintenance items should be considered when design decisions are made, as well as during regular

operation. There is risk of failure associated with the commutators commonly used in these systems. These concerns are common reasons that support replacing rotating systems with static exciters.

c. Brushless Rotating Excitation Systems.

(1) Brushless rotating excitation systems are relatively uncommon at present, though some early implementations of this sort of system were used. This technology is developing and is considered in specific instances.

(2) Brushless excitation systems consist substantially of the following components:

(a) A rotating PMG is mounted to the generator shaft or a coupled, dedicated shaft. The PMG serves to provide power to the excitation system as the generator reaches speed, eliminating the need for field flashing or voltage dependent sources.

(b) The static rectifier and controls cabinet converts the AC power generated by the PMG (or any alternative sources) into DC current. This DC current provides the excitation to the static field poles of the rotating brushless exciter.

(c) The rotating brushless exciter consists of the static field poles and a rotating armature winding. The field poles are mounted within the exciter housing on top of the generator and provide the flux for the rotating armature winding of the exciter. A three-phase rotating armature is mounted to either the generator shaft or a coupled shaft for the excitation system. Voltage is induced in the rotating armature windings due to excitation supplied to the static field poles and the shaft rotation. By controlling the DC current to the static field poles, the generated voltage of the rotating armature winding may be adjusted. Note that the static field poles and the rotating armature winding/rotating rectifier are relatively large components that often do not fit into existing rotating exciter housings.

(d) A rotating rectifier bridge then converts the AC voltage generated by the rotating armature winding into DC voltage, which is directly connected to the field winding. This rotating bridge may be composed of diodes or thyristors. If diodes are used, there is no further control of generator field voltage beyond varying field current to the rotating brushless exciter. If thyristors are used (requiring wireless controls), it is possible to modify the firing of the thyristors to control the generator field voltage more rapidly.

(3) Requirements pertaining to allowable control methods and cybersecurity may preclude the use of wireless controls that make thyristor operation possible. For some systems, if wireless communication is lost or not included, the thyristors are automatically triggered to function as diodes.

(4) Due to uncertainty surrounding the use of wireless communications and their reliability, brushless exciters are not currently considered for units with significant voltage response requirements. For this reason, these types of exciters are most considered for station service units or fishwater attraction units, which are not typically relied on for voltage response. It is also commonly desired that these units be able to start in cases where station power is not available, which brushless rotating exciters may support more readily than static systems.

(5) Brushless exciters present a challenge regarding both monitoring of generator field quantities and monitoring for field winding grounds. Unless wireless communication is used, there is no way to directly measure the generator field winding current or voltage.

(6) Measurement brushes may be provided for measuring field voltage, if desired. Additionally, field ground detection typically relies on a direct connection to the generator field circuit to detect resistance to ground. Again, brushes may be used to provide this functionality. As these are not current-conducting brushes and there are very few, they result in less wear and contamination than traditional slip ring or commutator brushes for maintenance purposes.

8–3. Power Potential Transformers

a. Transformer Type and Details.

(1) The PPT is typically supplied from the generator leads, though other arrangements are possible. The PPT is commonly procured as part of the excitation system equipment. The PPT should be a three-phase, 60-Hz, self-cooled, ventilated dry-type transformer, with vacuum-pressure impregnated (VPI) coils and copper windings. The PPT is generally fed from the generator bus with primary CLFs and designed for floor mounting. A low-voltage terminal chamber is provided with provisions for terminating the bus or cable to the excitation system power conversion equipment.

(2) When static excitation system replacements are being considered, it may be possible and economical to retain the existing PPT. This decision should be made considering age, condition, design details, and ratings of the PPT. Additional consideration for future excitation system requirements (due to uprate or major refurbishment work) should be made.

b. Rating Considerations.

(1) The high-side winding rated voltage of the PPT is determined by the voltage at the point of PPT connection. The low-side winding rated voltage is sized based on the ceiling voltage requirements of the excitation system. The Basic Lightning Impulse Insulation Level (BIL) rating should be selected to match the rating of the equipment the PPT is connected to on the high-voltage side, commonly the generator bus. It should be recognized that a higher BIL requirement can lead to a larger PPT enclosure size.

(2) The MVA rating for a PPT is driven by the continuous field current, ceiling field current, and ceiling voltage requirements of the exciter, which are specified. A specific MVA requirement for PPTs is not commonly specified, and various manufacturers have different design principles for the ratings of PPTs based on specification requirements.

(3) The temperature rise requirement should consider powerhouse temperature concerns in the area of installation. Additionally, consider that requiring a lower temperature rise may lead to a larger PPT (with respect to both weight and physical dimensions).

c. Auxiliary Equipment.

(1) PPTs are equipped with temperature monitoring of each phase that is used for alarming and tripping purposes. Alarm and trip settings should be based on equipment capabilities. Additional temperature elements (commonly RTDs) may be available, and may be wired to the exciter for display, trending, and additional alarm purposes.

(2) CLFs are installed on the high-voltage leads to the PPT. They are commonly installed within the PPT enclosure. These fuses act to reduce the available fault current at the PPT, as very high fault current is commonly available at their point of connection. These fuses can also serve as a clearance point for isolating the excitation system, and thus should be designed with consideration of safe removal and lock-out tag-out for

maintenance purposes. In some instances, and depending on Project requirements, a non-load-breaking disconnect switch may be considered as well. The benefit gained with these switches is not commonly deemed sufficient for the cost and physical space requirements.

(3) CTs are installed in the PPT enclosure and may be installed at either the high side or the low side of the winding. These CTs are used for overcurrent protection (device 50 and 51) and bridge failure detection via phase unbalance (either device 46 or 50Q/51Q functionality). These CTs are typically installed on the low-voltage winding of the PPT, as it simplifies measuring phase currents to the exciter and results in lower voltage class requirement. The exciter protective relay, which, for new equipment, is a digital multifunction relay (DMFR), uses these CTs and is typically mounted in the exciter cabinet(s).

8–4. Excitation System Sizing

a. Continuous Capabilities.

(1) *Field Current*. Excitation systems are sized based on generator field current requirements for rated operation, including additional margin in cases where a generator refurbishment is expected to take place. Any anticipated generator uprate should be considered as well, again allowing additional margin to account for uncertainty in estimated field current requirements. The system should provide sufficient field current to allow continuous operation at rated MVA output, at rated power factor, and at 105 percent of rated terminal voltage.

(2) *Field Voltage*. Continuous field voltage output capabilities for an excitation system are driven primarily by the ceiling voltage capabilities required. For this reason, continuous field voltage is typically not an explicit specification requirement.

b. Ceiling Capabilities.

(1) *Ceiling Current*. Typical USACE practice requires that excitation systems be capable of supplying 150 percent of rated field current for 30 seconds. This is consistent with IEEE Standard 421.4 and IEEE Standard C50.13 guidance relating ceiling current to field winding capability. Ceiling current greater than rated field current provides additional excitation to support system voltage during transient events.

(2) *Ceiling Voltage*. Ceiling voltage requirements have traditionally been determined based on the concept of an exciter's "nominal response," reflecting the magnitude and duration of an excitation system's response to voltage disturbances. With modern high initial response (HIR) exciters, however, a ceiling voltage requirement and supply voltage at which ceiling voltage must be reached is specified. Commonly, a ceiling voltage requirement of 150 percent of nominal field voltage (field voltage for nominal field current) is specified. It is typically required that this voltage be achievable with supply voltage to the high side of the PPT at 70 percent of nominal. This typical requirement is based on historical industry policies for excitation systems, particularly in the Western Electricity Coordinating Council (WECC) region and was based on the need for the exciter to provide sufficient current during faults that depress the local voltage for impedance-based relays to operate properly. Consult the utility to confirm the required capability.

(3) *Negative Field Forcing*. Full-inverting rectifier bridges can apply negative field voltage across the field winding to rapidly discharge the energy stored in the winding.

Manufacturer standard practices vary somewhat around the determining the maximum negative field forcing capability, but it is generally 90 percent of positive ceiling voltage capability. Specifications typically require that full negative field forcing be provided, with allowance for thyristor firing margin requirements.

8–5. Generator and Power System Considerations

a. 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.

b. 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 local power system. The unit will have to serve 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.

c. When operating in an "island," the unit may be required to operate in parallel with other units while running at speed-no-load to provide enough capacity to pick up blocks of load without tripping offline. 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.

d. For small units producing energy for a very large system, stability is not so critical since system voltage support is 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.

8–6. Regulator, Control, and Auxiliary Features

a. Automatic Voltage Regulator.

(1) Redundant excitation system controllers are typically provided, each of which includes an automatic voltage regulator (AVR) function as well as manual control. System controllers are solid-state, electronic elements, and on failure are not generally readily repaired. Having a redundant controller helps reduce risk of a forced outage due to controller failure. Additionally, having sufficient spare controllers is good practice, as well as maintaining familiarity with manufacturer support availability for the system.

(2) The excitation system control element includes an AVR function to maintain the generator voltage within a small tolerance of the reference setpoint. The AVR function of modern solid-state excitation equipment is an integral part of the system and includes digital control elements with microprocessor control. This type of control provides flexibility in changing regulator characteristics, precise and predictable control action, and minimal maintenance beyond replacing a failed device with a spare.

(3) The AVR system is tuned during commissioning, typically with two objectives to consider. The first objective is to maintain stable operation of the unit individually by ensuring that behavior of the regulator does not instigate unstable operation. The second objective is to provide optimal voltage support to the system to ensure stability, to the greatest extent possible. These two objectives can conflict, requiring a

compromise and careful selection of tuning parameters. Changing tuning parameters of the AVR should not be performed without thorough testing and analysis.

b. Manual Control.

(1) A manual regulation mode is provided within the excitation system controls that acts to directly control excitation applied to the field winding. Manual regulation may act to directly control field current or field voltage, though field current regulation is most common. Manual regulation is typically used only during specific testing or in case of failure of AVR operation. Manual regulation is not to be used during normal operation, as it results in decreased steady-state stability and voltage support capability and may result in some protection or limiter features being disabled.

(2) “Bumpless” transfer between regulator modes (AVR and manual) and between redundant controllers is required as standard practice. The bumpless transfer requirement means that the regulator control mode setpoints and the redundant controllers must track each other. In case of a transfer between modes or controllers without failure of voltage sensing, the transfer must not cause a terminal voltage deviation of greater than 1 percent. In case of voltage sensing loss, the transition to manual must not allow a deviation of greater than 7.5 percent terminal voltage and for no more than 0.75 seconds.

c. Power System Stabilizer.

(1) Power system stabilizer (PSS) equipment should be installed and functioning on generators according to regional system reliability compliance standards. The PSS function dampens power system oscillations by controlling the excitation system output in phase opposition to the oscillations. PSS works by sensing generator speed and power oscillations and applying excitation with appropriate phasing to dampen the detected oscillations. These oscillations can instigate unacceptable power swings between major loads and major generating plants in a widely dispersed power distribution grid.

(2) The PSS is allowed to be inactive while the turbine is operating within its “rough zone.” This ensures that the PSS is not acting to attempt to dampen speed oscillations originating from the turbine, which can cause excessive voltage and volt-ampere-reactive (VAR) swings. Two different AVR setting groups may be in place depending on the state of the PSS. Less aggressive AVR settings may be in place with PSS inactive, while more aggressive AVR settings can be in place with PSS active.

(3) PSS tuning entails determining the phase lag between excitation control action and the resulting change in rotor electrical torque. This phase lag is determined while online with no load and measuring the phase lag between field voltage and terminal voltage with a varying frequency sinusoidal input. In this way, the phase lag is determined at different frequencies, and the PSS may be tuned to compensate across the frequency range (commonly 0.2Hz to 1.0Hz). System conditions (lines in service, power flows, etc.) can impact the frequency response, therefore careful consideration of conditions during PSS tuning is needed.

d. Reactive Compensation.

(1) Reactive droop compensation may be used for units operated in parallel on a common low-voltage bus to allow stable sharing of reactive load in proportion to unit ratings. Reactive droop compensation reduces the voltage regulator setpoint slightly as

reactive output increases. The net effect is to stabilize unit operation when operating in parallel with other units and reduce reactive load swings between units.

(2) Similarly, reactive differential compensation may be used when units are connected on a common low-voltage bus to share reactive load in a stable manner. With this approach, communication between excitation systems is required that ensures that each unit does not counteract the change in reactive load of the other unit. This scheme allows reactive load sharing between parallel connected units while not reducing terminal voltage setpoint.

(3) Line drop compensation is a means of artificially relocating the point where the regulated voltage is sensed for the voltage regulation function. The generator output voltage is increased in proportion to reactive load to compensate for the voltage drop between the generator output terminals and the desired point on the system. The need for line drop compensation should be established by the utility to which the generator is connected. Close coordination with the utility is required to ensure power system voltage stability.

(4) Line drop compensation is functionally the inverse of reactive droop, as they both adjust voltage reference (up and down, respectively) based on reactive power output. Line drop compensation may not be used with paralleled units unless reactive differential compensation is included as well to ensure stable reactive load sharing.

e. Limiters and Protective Features.

(1) *Overview*. Many limiters and protective features are available within an exciter control system. The limiters that are made active, and their final settings, should be selected with care. Coordination with generator capability and protective relay settings should be confirmed (see Figure 8–5).

(2) *Over-Excitation Limiters*. Over-excitation limiters act to control the field current output from the excitation system by reducing the field current to a level below the limiter setpoint. This limiter primarily protects the generator field winding from overheating due to high current flow, though it may also consider other potential concerns (PPT and exciter ratings, for example). This limiter is typically an inverse-time overcurrent type. The farther the DC current output is above the limiter setpoint, the less time it takes for the limiter to activate and drive the field current down.

(3) *Under-Excitation Limiter*. Under-excitation limiters serve to ensure that excitation to the generator field winding remains sufficient to prevent loss of -synchronism or steady-state instability. It also acts to prevent operating in such a condition that trips the unit offline due to generator loss of excitation protective relay (device 40) operation. It operates as an instantaneous look-up type limiter that is based on real and reactive power output from the generator (commonly termed a “P/Q limiter”). The basis for the settings for this limiter can come from generator manufacturer-provided capability curves if available. Settings should be coordinated with generator loss of excitation protective relay settings (device 40).

(4) *Volts per Hertz Limiter*. Volts per Hertz (V/Hz) limiters operate by calculating the ratio of generator terminal voltage to operating frequency per unit. This limiter prevents over-fluxing of the generator core iron, as well as potentially connected equipment (generator step-up transformers, in particular). The settings of this limiter must be coordinated with generator protective relay settings, and sometimes the generator step-up transformer protective relay settings (device 24).

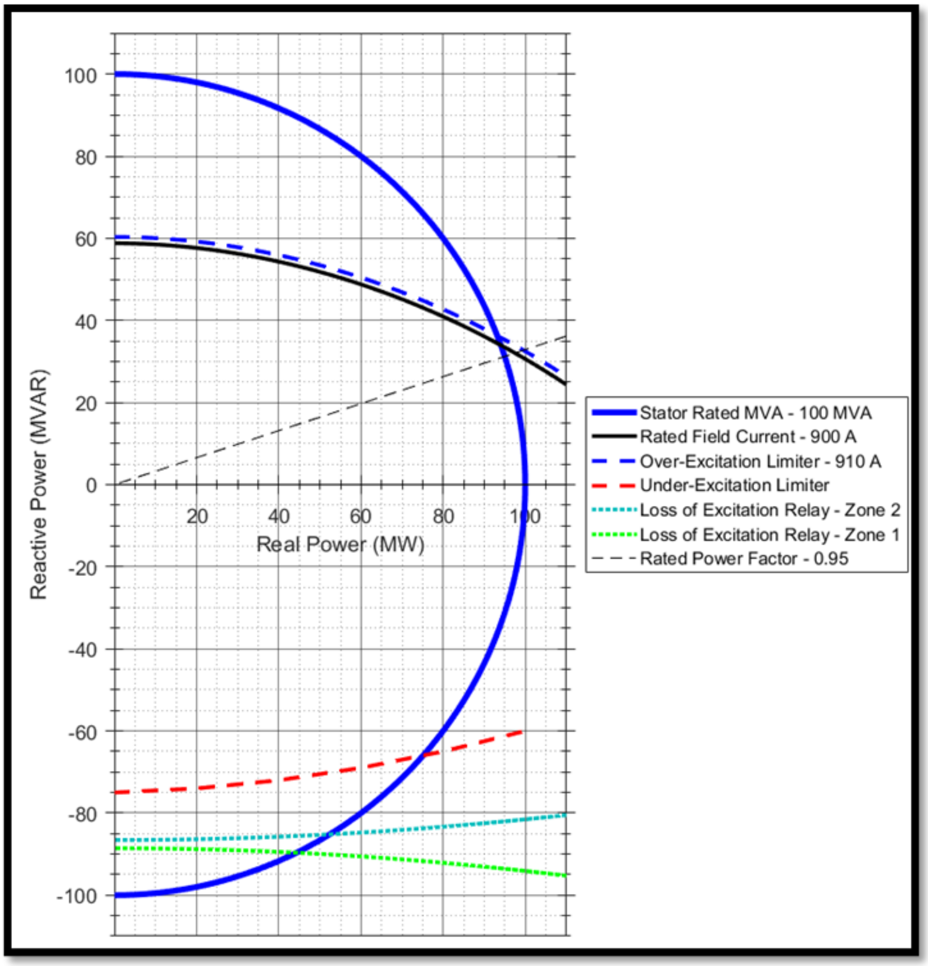


Figure 8–5. Generator reactive capability curve, showing common excitation limiters

(5) *Exciter Protective Trip.* The excitation system may send a trip to the generator controls based on several internal problems. These may include severe overheating, bridge failure, and complete failure of rectifier bridge cooling fans, among other items. The exciter trip command may also be triggered by elements within the exciter protective relay (PPT overcurrent, phase unbalance) or the PPT temperature monitoring system (overheating).

(6) *Other Limiters and Protective Features*.

(a) Other limiters that may be included as options by excitation system manufacturers include stator current limiters and terminal voltage limiters. These limiters are not typically active for USACE hydroelectric units. Using them can lead to coordination challenges with protective relaying and automated controls. They can also cause unexpected control action under adverse system conditions, and unnecessarily limit unit capabilities if not set or implemented appropriately.

(b) Other protective features that may be included as options by excitation system manufacturers can include V/Hz protection trip, generator overvoltage trip, and others. These additional protective features are typically not used as they lead to coordination

challenges with stand-alone protective relaying, in many cases duplicating functionality already implemented.

f. Field Flashing. Momentary connection of a DC source of proper polarity to the generator field (field flashing) should also be required in most cases. Field flashing provides prompt and reliable buildup of generator voltage without reliance on residual magnetism when the exciter is supplied by the generator terminals. The simplest source for field flashing voltage is the station battery. If the unit is not required to have black start capability, an alternative is to use an AC power source with rectification to supply DC field flashing.

8–7. External Controls, Devices, and Annunciation

a. External Controls. The design and implementation of excitation system controls throughout the powerhouse may vary greatly depending on the configuration of the powerhouse and operational practices. During excitation system installation or replacement, exciter control switches are commonly replaced to better suit operation with the new equipment. Consistency of switch types within the same panel should be considered during the design. A thorough assessment of exciter controls should be performed for new systems. Potential locations for excitation system control include:

(1) *Excitation System Cabinets.* Control via the excitation system cabinets, either via the HMI or switches mounted on the exterior of the cabinet, is commonly considered “local” control. Control actions may be taken using the HMI, and settings changes may be performed with sufficient user account permissions. Specific functionality available through the HMI may vary between manufacturers. An emergency trip switch or button is commonly provided on the exterior of the exciter cabinets.

(2) *Unit Control Switchboard*. A unit control switchboard may be located near the generator unit and may include controls for one or more units. This switchboard may include hardwired control switches for exciter control. Commonly, these switches include an adjustment switch (raise/lower), operating mode switch (AVR-Field Current Regulator [FCR]), and local/remote switch. A local/remote switch in this location typically disallows operation from the control room or automated controls when placed in “local.” An additional control switch may also be included here to block the exciter from starting when the generator reaches speed.

(3) *Control Room*. The switchboard in the control room typically includes exciter controls such as an adjustment switch (raise/lower) and a mode switch (AVR/FCR). An additional control switch to block the excitation system from starting as described above may also be installed here. Additionally, a remote HMI located in the control room is sometimes provided to allow operation of several exciters from a single convenient location.

(4) *Automated Controls*. Supervisory controls and data acquisition (SCADA) systems are in place at many powerhouses, and through output contacts may perform excitation system controls. Excitation system controls from SCADA systems are typically limited to only “raise” and “lower” adjustment controls. Modbus control may be available as well, though operational security and cybersecurity risks and compliance must be thoroughly considered. Modbus control is not commonly implemented for these reasons.

(5) *Auxiliary Devices*. Some additional devices such as automatic synchronizers and some voltage-related protection relays may have contacts that are used to issue input controls to excitation systems. These contacts serve as additional sources to raise and lower adjustment control. Generator protection devices such as complete shutdown (device 5C) and lockout (device 86) may be connected to provide an “external trip” signal to the exciter.

b. Annunciation and Indication. Annunciation and indication specifics vary significantly among powerhouses based on arrangement and operational practices. The specifics of the planned annunciation and indication approach for an excitation system should be designed based on operational practices and preferences.

(1) *Excitation System Cabinets*. The HMI commonly provided with new excitation systems typically serves as the primary form of annunciation and indication. Various alarms, limiter states, and operational data may be viewed readily from the main screen. Alternatively, or in addition, various annunciating lights and indicating gauges may be mounted on the exciter cabinet to view operating status.

(2) *Unit Control Switchboard*. The unit control switchboard commonly includes a unit annunciator as well as indicating lights and gauges. The annunciator commonly includes at least two positions for exciter purposes; one for “Exciter Trip,” and one for “Exciter Trouble.” The former is typically configured to indicate that a trip was initiated that originated from the exciter. The latter indicates there is some abnormal condition with the exciter. In either case, details of the event are most readily found at the exciter itself. Indicating lights and gauges may also be included here for limiter/mode status and field voltage/current, respectively. Any field voltage/current signals sent outside the exciter should be in a transduced form (commonly 4-20 mA) to avoid potentially hazardous voltages and voltage surges reaching control boards.

(3) *Control Room Switchboard*. The control room usually includes a similar annunciation and indication as the unit control switchboard, though it may be greatly reduced depending on plant arrangement. The purpose of the annunciation and indication here is to provide rapid feedback to operators about the current state of the exciters and any concerns regarding their operation.

(4) *Automated Controls*. SCADA systems can accept many digital and analog inputs. Because of this, they may be able to accept a wide array of specific signals pertaining to exciter operation (specific alarm and trip descriptions, limiter operation, operating modes, PSS status, etc.). SCADA systems may accept Modbus-based annunciation and indication, which allows all outputs from the exciter to be received in a single connection. Cybersecurity compliance and operational security risks should be considered if Modbus annunciation is provided. It may also be possible to implement Modbus-based controls, in which case the cybersecurity concerns are increased.

c. External Instrument Transformers.

(1) Dedicated generator CTs and PTs should be supplied to service the excitation system voltage regulators. These CTs and PTs are used by the exciters to calculate operating real and reactive power, terminal voltage, and frequency. These signals are critical to successful operation of AVR and PSS functionality as well as limiter operation.

(2) PTs may be provided in wye or open-delta configuration, and at least one phase CT must be provided. Multiple reputable manufacturers can implement an effective PSS with only a single CT available. With three CTs available, the

measurements and calculations made by the exciter can be less noisy, which can allow higher exciter and PSS gains to be used. This results in a more responsive exciter with a higher gain PSS, which can be more effective in damping system oscillations. The necessity for a higher gain exciter or PSS varies across regions, and the utility should be consulted to determine the requirements for any given region.

(3) These instrument transformers can often be advantageously mounted in metal-clad (MC) switchgear, cubicles, or metal-enclosed (ME) bus runs, where they are associated with similar instrument transformers for metering and relay service. Alternative installation locations may be considered, especially if additional CTs or PTs for the exciters are needed after installing the existing equipment.

8–8. Exciter Testing and Commissioning

a. Factory testing the excitation system components is recommended to reduce the risk of unnecessarily extending the unit outage due to problems encountered in the field. Exciter factory testing should include dielectric testing of components per IEEE Standard 421.3 requirements, functional testing of controls, and rated and overload current testing. PPT factory testing should include routine electrical testing as described in IEEE Standard C57.12.91, as well as temperature rise and load loss testing. Performing an insulation power factor test on the PPT in the factory may also be considered, as it can assist in confirming complete curing of the insulation system.

b. Upon installation, commissioning and testing should confirm that the equipment was installed correctly, and functions as designed and required. Testing should also confirm that dynamic tuning and limiter and control elements function in a stable manner, and that settings are appropriate and well-coordinated. Load testing should be performed as well to confirm that no equipment or connections overheat when operated at full field current during regular operation.

c. NERC model verification testing can be performed concurrently with commissioning to determine dynamic models per NERC MOD-026 requirements. Many of the tests performed during commissioning activities are identical to the tests required for NERC compliance. Ensure that all test data is collected with final settings in place as applicable for reporting purposes, as settings are commonly adjusted throughout commissioning. Note that some regions may have additional dynamic modeling compliance requirements. Refer to IEEE Standard 421.5 for more information regarding exciter, PSS, and limiter modeling practices.

Chapter 9
Generator Bus, Neutral Grounding, Surge Protection, and Instrument Transformers

9–1. General

a. The generator equipment 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 terminals of the generator and the power plant grounding system. The equipment not covered herein is the generator breakers, which are covered separately in Chapter 10.

b. This section is intended for main unit generators 10 MVA and higher but may be considered for smaller station service units or fish attraction water units down to 3 MVA. The equipment generally associated with the generator-voltage system includes instrument transformers for metering, relaying, and generator excitation systems, neutral grounding equipment, and surge protection equipment. The equipment is classified as medium-voltage equipment, rated from 4.76 kV to 15.5 kV for USACE powerhouse applications.

9–2. Generator Leads

The term “generator leads” applies to the circuits between the generator terminals and the low-voltage terminals of the GSU transformers. The type of equipment selected for the generator lead design depends on the distance between the generator and transformer, the capacity of the generator, the presence of a generator circuit breaker or disconnect switch, physical limitations, and the economics of the installation.

a. *Generator Variations*. Generator leads may consist of solid bus (ME or resin-insulated) or insulated medium-voltage cables, variations of which are discussed in greater detail below. Selecting a specific type of generator lead should also give preference to minimizing the possibility of severe damage from high phase-to-phase faults. For example, nonsegregated-phase bus is more compact and economical than other solid bus types, but it relies only on air to separate the phases inside the enclosure—external physical damage to the bus enclosure is more likely to cause such a fault; cables in tray or in cable bus may be more economical, but this typically requires several cables per phase—the flexibility of cable becomes more of a liability from the electromagnetic forces between the phases during a fault.

b. *Solid Bus Connections*. For all solid bus connections to the GSU transformer low-voltage bushings, the transition housing must be detailed or be called out as a contractor-designed detail for approval to ensure that the bus manufacturer’s design is compatible with the GSU transformer manufacturer’s design at the low-voltage bushings.

c. *Cable Connections*. For all cable connections, there must be sufficient space for the minimum cable bend radius and transition to lugs for connection to the low-voltage bushings.

d. *Metal Bus*. Metal-enclosed bus includes nonsegregated-phase, segregated-phase, and isolated-phase, all using air as the insulating medium between the grounded enclosure and the phase conductors as described below. Each type of ME bus has specific applications depending mainly on current rating. ME bus is covered by

IEEE C37.23. Any type of ME bus that passes through a wall, floor, or any concrete structure separating indoors from outdoors should use through-bushings or seal-off bushings to provide an environmentally tight interface.

e. *Nonsegregated-Phase Bus* (also referred to as nonseg bus). All phase conductors are enclosed in a common metal enclosure without barriers, using air as the insulating medium between phases. The phase conductors are insulated from the grounded enclosure with molded material and supported on composite or porcelain insulators. This bus arrangement is normally used with MC switchgear and is available in ratings up to 4,000 A (6,000 A in 15 kV applications). Although IEEE C37.23 allows ratings for 15.5 kV/110 kV basic impulse level (BIL) nonseg bus, most manufacturers offer only 15.0 kV/95 kV BIL nonseg bus. If a 110 kV BIL rating is required, segregated-phase bus or a type of isolated-phase bus is recommended.

f. *Segregated-Phase Bus* (also referred to as seg bus). All phase conductors are enclosed in a common enclosure, but are segregated by grounded metal barriers between phases. Conductor supports are usually porcelain. This bus arrangement is available in the same voltage and current ratings as nonsegregated-phase bus but with ratings matching those of Class S2 generator breakers: 15.5 kV and 110 kV BIL.

g. *Isolated-Phase Bus* (also referred to as isophase bus or IPB). Each phase conductor is enclosed by an individual metal housing.

(1) Conductor supports are usually porcelain. Isophase bus starts with a 15.5 kV voltage rating and either 110 kV or 125 kV BIL rating. Current ratings are available up to 24,000 A for self-cooled bus, and up to 50,000 A using forced-air cooling. Self-cooling is preferred to eliminate the cooling system as a possible point of failure that would operationally de-rate the bus and connected generator.

(2) On systems where the three-phase generator is connected to a bank of three single-phase transformers (typically systems like this are too large for nonseg bus), a transition is required to change the three-phase isophase bus from the generator breaker to three single-phase isophase bus risers (phases AB, BC, and CA) to the delta-connected single-phase transformers. This transition is known as a “delta bus” (see Figure 9–1). Each riser should be sized for the MVA of the connected single-phase transformer, whereas the isophase bus from the generator to the delta bus should be sized for the MVA of the generator. The sections of delta bus are sized for the current they will carry, and are likely different than the other sections noted above.

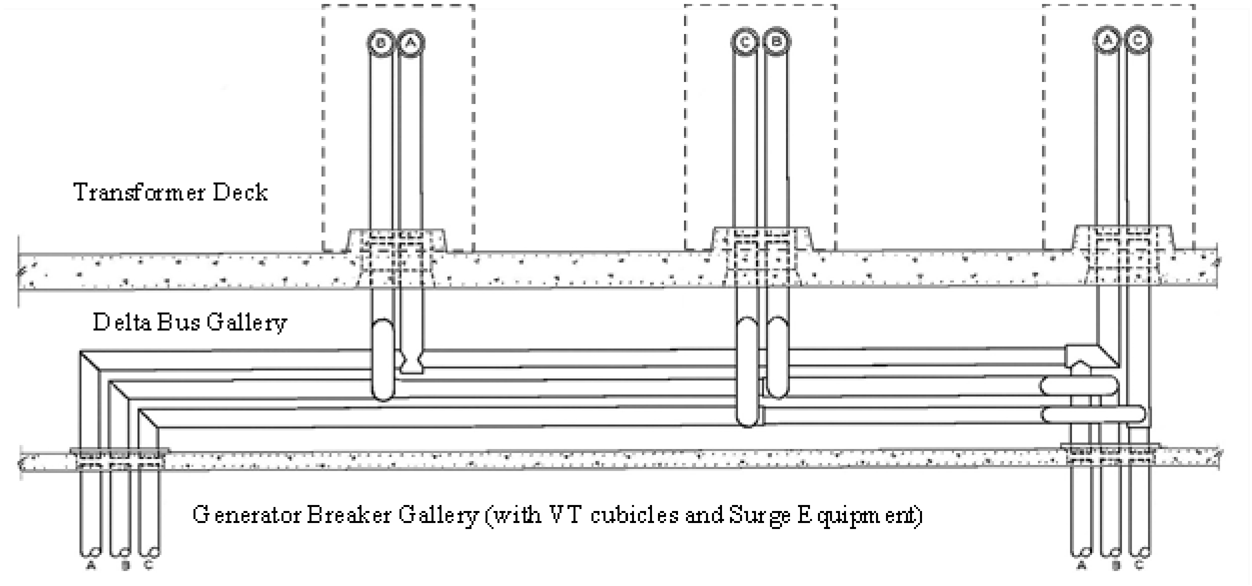


Figure 9–1. Elevation view of typical delta bus configuration for a bank of single-phase generator step-up transformers

(3) Bus housing type must be considered.

(a) Isophase bus is now available mostly with a continuous housing design. Continuous designs provide an electrically continuous housing, thereby controlling external magnetic flux and lessening the number of ground connection points and ground loops. Non-continuous designs are less effective at external magnetic flux control.

(b) Non-continuous enclosures are often joined together by section, where one of the phase enclosures serves as the ground conductor to which all the other sections are grounded. This “ground enclosure” is grounded in one place to powerhouse ground in each grounding zone, typically one zone above the breaker and another zone below the breaker. Flux shunts or shorting bands are used to protect nearby steel structures from eddy current heating on buses with either continuous enclosures or non-continuous enclosures. This is typically done with isophase bus rated 4,000 amps or higher in each section. Most USACE powerhouses were constructed using non-continuous isophase bus housing designs, which was normal design practice at the time of installation, but this type of housing has fallen out of favor with the isophase bus industry and users alike.

(c) If replacing just a portion of existing isophase bus with a non-continuous housing, the specifications must clearly state that the new isophase bus must either match the existing non-continuous design or that the manufacturer’s design includes a suitable interface between the existing housings and the new housings. If a non-continuous housing is absolutely required, additional design cost and lead time should be expected.

(4) Bus conductor type must be considered.

(a) Older USACE powerhouses were constructed with isophase bus having copper conductor; however, copper conductor has higher material prices and weight. Although IEEE C37.23 allows copper or aluminum, copper has the potential to impact schedule and costs.

(b) If new aluminum conductors are to be connected to existing copper conductors, the specifications must include a design requirement for a suitable copper-to-aluminum connection.

(c) If copper conductor is absolutely required for the new isophase bus, it must be made clear in the specifications; otherwise, bidders will presume aluminum and bid accordingly. The independent Government estimate must address the added cost of copper, and the construction schedule must also account for the additional lead time.

h. Resin Insulated Solid Bus.

(1) A relatively new type of rigid bus using solid dielectric insulation over rigid bus or pipe is now being used. It is much more compact than traditional isophase because air space is not used as the insulating medium, yet the phases are completely isolated from each other, unlike segregated-phase bus having a common enclosure.

(2) There is no standard generic term for this type of bus other than trade names that are proprietary. Manufacturers' data refers to this product generically as "solid-insulated" or "resin-insulated" bus. There are presently no NEMA, American National Standards Institute (ANSI), or IEEE standards covering this design, which originated in Europe; however, manufacturers' data indicates performance requirements and ratings similar to traditional isophase bus, except that the lowest acceptable standard voltage rating is 17.5 kV.

(3) If this product is to be specified, the specification should reference IEC 62271-201 instead of IEEE C37.23.

(4) There are three known manufacturers of this particular type of bus, one of which is domestic, so sole-source approval should not be required (at the time of this publication). If this type of bus is proposed for new or replacement installation, the Contracting Office of the participating USACE District should be consulted to verify acceptability within all acquisition regulations, as contract cost may affect applicability with just one domestic source available.

i. Bus Taps. Bus taps (essentially a tee-connection) are often used on all solid bus types to power station service, and to power the PPT for main unit exciters. PPT taps should be between the generator and the generator breaker, while station service taps may be on either side of the generator breaker. PPTs are covered in Chapter 8. Station service is covered in Chapter 15.

j. Solid-Dielectric, Medium-Voltage Cable.

(1) Solid-dielectric, medium-voltage cable (see Chapter 31) may be used in cable tray or cable bus. For very large gauge cables (in the 1,500–3,000 kcmil [thousands of circular mils] range) custom-designed suspension systems using saddle-type supports are recommended instead of cable tray, and are described in Chapter 33. Cable bus is typically not available in such large gauges. Thermal expansion of cable is always a concern for uprates and new installations. A mechanical engineer should evaluate the HVAC requirements to keep the cables within their recommended full load operating temperature.

(2) In all cases for large generators, multiple cables per phase are required. Thermal expansion and contraction must be accounted for where cable size reaches 1,250 kcmil, at which point cable tray and cable bus become impractical. The preferred cable for generator leads is Type MV-105 using ethylene propylene rubber (EPR) insulation. The use of parallel conductors to reduce cable size should be limited to four per phase where possible when replacements are being made in confined enclosures requiring connection to existing solid bus. Where more than three current-carrying cables share the same conduit, ampacity deratings must be applied; where cables are paralleled in cable tray, minimum spacing allowed between phases must be considered for all cables in the tray.

(3) Medium-voltage cable terminations typically require between 1.2 and 1.5 times the cable diameter for termination diameter, and between 3 and 6 times the cable diameter for termination length depending on the bolted connector.

(4) When cables 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 amount of tunnel ventilation required to dissipate the heat generated by these losses. This becomes critical where generator uprates may require additional ventilation in the tunnel.

(5) The generator neutral grounding method and relaying should also be considered. Because USACE main unit generators are almost always configured with reactance or resistance grounded neutrals, Insulated Cable Engineers Association (ICEA)/NEMA standards for cable rated over 2,000 volts requires an insulation level of 133 percent even though powerhouse practice is to trip within 10 to 15 seconds when a ground fault is detected.

(6) Cable tray is commonly used. Where several cable trays must be stacked to run the same generator leads, consideration should be given to cable bus. Cable tray fill limitations are covered in National Electrical Code (NEC) Article 392. Medium-voltage cable ampacity is covered in the later tables of the NEC Article 310. See Chapter 33 for more information.

(7) Cable bus is similar to cable tray except that the structure allows several vertical layers of cables having NEC-compliant spacing as well as NEC-compliant horizontal spacing in each vertical layer. Cable bus is suitable for any size conductor up to 1,000 kcmil. Cable bus requirements and limitations are covered in the NEC Article 370.

k. Oil-Filled Cable Systems.

(1) Oil-filled cable systems use oil pressurized to 200 psi (1379 kPa) inside a large pipe containing laminated paper-insulated, single-conductor cables. All phase conductors are typically enclosed in the same pipe even if multiple conductors per phase are used. These are referred to as high-pressure fluid-filled (HPFF) systems.

(2) Nitrogen-type cables are three-conductor, paper-insulated, oil-impregnated cables in a lead sheath with channels between the phase conductors to transmit nitrogen at 10–20 psi (68.9-137.9 kPa) to improve dielectric strength. These are referred to as low-pressure gas-filled (LPGF) systems.

(3) Many USACE powerhouses were constructed in the 1940s through the 1970s using HPFF or LPGF generator leads at 13.8 kV. In the 1980s, the industry standards supporting HPFF and LPGF cable systems changed to eliminate applications at

voltages below 69 kV. Thus, replacement-in-kind is no longer an option for powerhouses requiring replacement of these systems.

9–3. Neutral Grounding Equipment

All main unit generators at USACE powerhouses have the windings in a wye configuration, providing a neutral point that must be grounded. Generator grounding is covered by IEEE C37.101 Part 6 and IEEE C62.92.2.

a. The neutral grounding conductor may be either solid bus or insulated cable.

b. Solid neutral grounding is not feasible on main unit generators due to very high ground fault currents that could be several times higher than available three-phase fault current, which is not allowed by synchronous machine standards (IEEE C50.12). Neutral grounding methods are chosen to reduce the single line-to-ground fault current to no higher than that in a three-phase fault, or to much lower levels to minimize core damage due to single line-to-ground faults. The objectives for neutral grounding include minimizing mechanical damage from internal ground faults, minimizing mechanical stress from external ground faults, limiting temporary overvoltages (TOV), providing a means of detecting generator ground faults, and coordinating generator protection with other connected equipment.

c. All grounding should be done through a circuit breaker or disconnect switch to allow isolation for maintenance purposes.

(1) Reactance grounding of main unit generator neutrals was used in the construction of most USACE powerhouses. These were typically resonant-grounded systems in which the reactor was sized to provide an inductive current to match the capacitive ground current. Beyond the breaker or disconnect switch, the ground path goes through a medium-voltage reactor, which typically limits ground faults to magnitudes of 25 percent to 60 percent of three-phase fault magnitude.

(2) Low-resistance grounding of main unit generator neutrals typically has a medium-voltage resistor in series with the neutral conductor.

(3) High-resistance grounding (HRG) uses a distribution transformer to reduce the medium-level voltage to a low-voltage level to allow using smaller and less expensive resistor. The turns ratio of the transformer increases the resistance seen by the generator neutral by a factor of the square of the turns ratio.

(a) HRGs are typically designed to limit ground fault current to between 7 and 10 amperes.

(b) Many USACE reactor-grounded generators have been upgraded with HRGs in recent years and are recommended where reactance grounding is still used when units are uprated. The entire system at that voltage level must be included in the HRG calculations. Relay settings should also be checked in case changes are needed. The calculations described in the referenced IEEE standards to size the resistors and the step-down distribution transformer must account for all system capacitances, including the generator surge protection capacitors and breaker transient recovery voltage capacitors.

9–4. Generator Surge Protection

Voltage surges occurring on the generator bus can be caused by lightning strikes on the transmission line or by switching transients, particularly by the operation of the generator breaker. When the overvoltage reaches the design conduction limit of the connected surge arrester, the current gets shunted to ground, thus alleviating the voltage surge.

a. Surge Arresters.

(1) Surge arresters absorb and conduct the excess energy of a surge to ground. They should not be confused with surge suppressors or surge protectors, which often have electronic components and resistors to help absorb the excess energy and covert most of it to heat. The industry standards covering surge arresters are IEEE C62.11 and IEEE C62.22. Older surge arresters generally consist of silicon carbide resistor blocks in series with air gaps; however, they are not as robust as modern surge arresters containing metal oxide (primarily zinc) with no air gaps. Metal oxide arresters typically have better protective levels than silicon arresters.

(2) Where silicon carbide surge arresters are still in use, they should be replaced with metal oxide surge arresters during the next opportune occurrence of electrical upgrades. Silicon arresters are prone to moisture ingress and failure, and should be replaced after 20 years in service. Additional guidance on surge protection can be found in IEEE C62.23.

(3) The relevant surge arrester rating is its maximum continuous operating voltage (MCOV), which is typically about 80–85 percent of its historical duty cycle voltage rating. Surge arresters should primarily be specified by MCOV and not simply by the nominal system voltage rating.

(a) Since surge arresters are connected phase-to-ground, the normal practice is to size the arrester MCOV based on phase-to-ground voltage. However, all USACE hydropower main unit generators are wye-wound with a resistance- or reactance-grounded neutral, making it possible for line-to-ground voltages to be elevated to phase-to-phase levels for the unfaulted phases during a line-to-ground fault. Thus, the recommended practice for sizing surge arrester MCOV should be based on the neutral grounding method implemented for the generators.

(b) Other surge arrester ratings governed by IEEE C62.11 and IEEE C62.22 may be selected based on the insulation coordination study of the nearby power system equipment.

(4) Station class surge arresters undergo the most stringent testing required. Although they are more expensive than the lesser Intermediate and Distribution classes, they are highly recommended for protecting rotating machinery in excess of 1 MVA. Surge arresters for generator protection are installed near the generator terminals. In addition to stating the required MCOV, the specifications should also be required to be “station class.”

b. Surge Capacitors.

(1) Surge capacitors are almost always used in parallel connection with surge arresters for large synchronous generators because the capacitors reduce the frequency and the magnitude of transient voltages (TRVs). Although metal oxide surge arresters do a good job of limiting the magnitude of surge overvoltage, they have no effect on controlling the voltage rate of rise. Surge capacitors are designed with low internal inductance to limit the rate of rise of the surge overvoltage by reducing the steepness of the wave front, and thus better protect turn-to-turn insulation.

(2) It is industry standard to specify 0.5 microfarad (µf) capacitors on systems between 4.16 kV and 7.2 kV, and 0.25 µf capacitors on systems between 13.8 kV and 14.4kV (15 kV).

c. Arrester and Capacitor Locations. Surge arresters and capacitors are typically located in the separate equipment cubicles housing the PTs for generators, where the generators are large enough to require isolated-phase bus. For smaller systems where nonsegregated-phase bus is used, the surge equipment is typically installed within the MC switchgear lineup housing the generator breaker.

9–5. Instrument Transformers

a. Instrument transformers for metering. Instrument transformers are used for metering the generator output and for generator protective relaying. Relays and meters typically cannot directly measure the utilization voltage and current of main unit generators. Instrument transformers, which include potential (voltage) transformers and CTs, measure these utilization values and provide an equivalent of typically 120VAC and 5 amps maximum for use by the relays and meters.

b. Potential transformer. The term “potential transformer” should not be confused with the term “power potential transformer,” which is part of an excitation system and is not an instrument transformer. Instrument transformers are covered by IEEE C57.13.

c. Other standards. Additional helpful standards are IEEE C37.110 and IEEE C57.13.3.

d. Voltage transformers. The voltage rating and BIL of voltage transformers CTs are selected to match the system voltage, as shown in Table 9–1 (see also IEEE C57.13, Table 2). The exception is that bushing or window-type CTs have 600-volt and 10 kV BIL ratings regardless of system voltage because they are not physically connected to system voltage conductors, which is permitted by IEEE C57.13. Bar-type CTs must have voltage ratings matching the system voltage ratings.

Table 9–1
Voltage ratings for instrument transformers

Rated Voltage kV	Rated Impulse Level (BIL), kV
0.6	10
5.0	60
8.7	75
15	95[a]
15	110*

[a] 110 kV is required for isolated-phase bus cubicles and where generator breakers are available with a 110 kV BIL rating. See Chapter 10.

e. Instrument Transformer Grounding

(1) Instrument transformer secondary grounding should occur at only one point of the station ground system.

(2) This instrument transformer grounding prevents circulating currents and avoids using the station ground bus as part of the secondary circuit. IEEE C57.13.3

recommends that the grounding point be physically closest to the first point of application of the secondary circuit. In other words, the neutral wire or open delta point to be grounded follows the circuit conductors to their point of connection, and that is where the ground connection should be made. This point is usually where the protective relays (overcurrent, differential, ground fault, etc.) and meters (ammeter, voltmeter, wattmeter, etc.) are located, typically in a relay panel or control switchboard in the powerhouse control room.

(3) For small station service installations and pumphouses, these devices may all be located in the switchgear itself. The instrument transformer secondaries should not be grounded in the switchgear unless the relays and meters are located in the switchgear.

f. *Nomenclature*. Voltage transformers have been commonly referred to as PTs (or P-T, or P/T). However, the official nomenclature used in IEEE C57.13 is “voltage transformer” and should be abbreviated as VT. Some manufacturers offer single-bushing voltage transformers for grounded-wye configurations where the rated primary voltage might be limited to line-to-neutral (L-N) system voltage instead of line-to-line (L-L) and rated secondary voltage might be 69.3V instead of 120V. However, recommended hydroelectric powerhouse practice is to have all voltage transformers rated for L-L primary voltage and 120V secondary voltage because those potentials are present inside the switchgear housing regardless of wiring configuration. This does not affect the accuracy of the voltage transformers in grounded-wye systems.

(1) *Voltages*. Standard rated primary voltages, voltage ratios, and BIL ratings are listed in IEEE C57.13. In general, the voltage and BIL end up being the same as, or similar to, the rated primary voltage and BIL of the switchgear circuit breakers.

(2) *Thermal rating*. The thermal rating, also called thermal burden, is a measure of how many volt-amperes (VA) the VT can carry at rated secondary load without exceeding the required temperature rise. Typically, an increase in thermal rating increases the physical size required of the VT. The thermal burden is typically higher than the accuracy burden.

(3) *Burden*. Accuracy burden, typically just called burden, is a measure of how many volt-amperes the VT can carry at rated secondary load and remain within the required accuracy percentage. Older generator switchgear relying on electromechanical relays required higher burden VTs than those now required by digital relays. When upgrading or replacing existing generator switchgear, perform a burden analysis to match the new VTs to the new relays and meters rather than simply matching the burden rating of existing VTs to verify that the VTs are properly sized.

(4) *Accuracy classification*. Accuracy classification is a measure of how much error a voltage transformer might exhibit while operating within 90 to 100 percent of rated voltage for metering purposes.

(a) IEEE C57.13 standard values are 0.3, 0.6, and 1.2 percent. The lower the number, the greater the accuracy. The designations W, X, M, Y, Z, and ZZ identify the standard burdens (listed in order of increasing volt-amperes and decreasing inductance) used by IEEE C57.13 for test purposes at various power factors. Impedances associated with each accuracy class depend on the secondary voltage: 120 volts line to line, or 69.3 volts line to neutral.

(b) Many manufacturers have difficulty getting a 0.3 or 0.6 percent accuracy for the Z and ZZ standard burdens, but those combinations of volt-amperes and power factors are expected only during system disturbances such as short circuit, in which case the accuracy for metering purposes is of less concern.

(5) *Wiring*. Wiring configurations must be shown on the one-line or three-line diagrams in the contract drawings with the desired fusing. Fuse type and size may be determined by the manufacturer.

(a) For input to a generator exciter, previous practice was to have two VTs wired in open-delta configuration; however, three VTs wired in wye configuration are preferred for modern digital exciters with power system stabilizers. These should be located on the generator side of the generator circuit breaker.

(b) Three voltage transformers wired in wye configuration are typically used for metering and possibly some relaying. These may be located on either side of the circuit breaker, but preferably on the source side. These functions may be combined on the source side if space limitations demand, but the total burden of the relays and meters must not exceed the VT burden ratings. Some units may have originally been installed with open-delta VTs, however three VTs wired in wye configuration is recommended for digital relaying.

(c) Synchronizing schemes for closing generator circuit breakers into the utility grid use voltage transformers to monitor frequency on both the source side and load side of the generator breaker. Older synchronizing schemes often used just one voltage transformer located on the B-phase of the generator lead and on the B-phase of either the high-voltage switchyard bus or a bushing potential device at the generator step-up transformer bushing. Synchronizing the closing of generator breakers is more accurately done by having VTs on at least the B phase of the generator leads on both sides of the generator breaker. This avoids inaccuracies introduced by the impedance of the GSU transformer.

(6) Installation Requirements

(a) Installation of VTs should be in drawout compartments separate from the generator breaker. For isolated-phase bus installations, a dedicated VT cubicle having one drawer for each VT is often used with a direct isolated-phase bus connection. These cubicles should be included with the isolated-phase bus procurement as they are typically built by the same manufacturer. Adjacent cubicles also often contain the surge protection equipment.

(b) Smaller systems using a MC switchgear lineup for the generator breakers should have the drawout VTs in the compartment nearest to the breaker.

(c) For either configuration, each VT should be in a fused rollout tray that disconnects and grounds the VT in the withdrawn position. Current-limiting fuses are required for each phase connection on the VT primary side. VT secondary fusing should be in the cubicle low-voltage compartment.

g. *Current transformer*. While the term “current transformer” is commonly abbreviated C/T or C-T, CT is recommended.

(1) In addition to the IEEE standards listed above, the following IEC standards apply specifically to CTs: IEC 61869-1 and IEC 61869-2. If the new CTs are replacing existing CTs, do not simply match the existing CT ratings without first verifying the

proper CT ratings for the new installation. The CTs should be designed to withstand the momentary currents and short-circuit stresses for which the bus or switchgear is rated.

(2) A CT with a given core dimension can support only a given amount of maximum flux density in the core. As long as the flux density in the core (which is created by CT primary current flow) remains below what the maximum flux density is, a change in flux creates a current flow in secondary circuit corresponding to the CT ratio in a nearly linear fashion. But if the primary current gets too high, the core cannot handle any more flux and the CT is said to be in saturation. In saturation, there is little flux change when the primary current changes and the relationship is no longer linear. This is especially critical for differential relaying, where very slight changes in CT response accuracy have significance.

(3) Standard rated current ratios and BIL ratings are listed in IEEE C57.13. For bar type CTs in series with the switchgear bus, the BIL ends up being the same as the rated BIL of the switchgear circuit breakers. For window-type CTs or bushing CTs, the BIL need only be 10 kV in switchgear rated 95 or 110 kV BIL because the air gap provides the added impulse protection.

(4) Current ratio indicates the amount of full load primary amps that deliver full rated secondary amps at the specified accuracies. IEEE C57.13 lists many standard current ratios, depending on whether the windings are single-ratio type or multi-ratio type.

(a) A multi-ratio (MR) CT has one single core with one secondary winding with taps to provide a selection of ratios, and must not be confused with two-core or split-core CTs. Note that the relaying accuracy of an MR CT is valid only at its highest ratio. The rated burden of MR CTs drops as the available ratios progress, resulting in a loss of accuracy in proportion to the ratio. This makes MR CTs undesirable differential relaying unless used on the highest ratio.

(b) Under IEEE C57.13, single-ratio CTs mostly have standard ratios of even numbers rounded to the nearest hundred or thousand, while MR CTs mostly have standard ratios and taps of the in-between numbers; however, many manufacturers offer most of these ratios as single-ratio CT, which is acceptable even though not listed as a single-ratio rating in IEEE C57.13, providing all other requirements are met.

(c) For most USACE hydroelectric powerhouses, the current ratios most typically used are shown in Table 9–2 for illustration; however, the designer is not limited to just these ratios.

Table 9–2
Typical current transformer ratios

15:5	100:5	600:5	3000:5
25:5	150:5	800:5	4000:5
40:5	200:5	1200:5	6000:5
50:5	300:5	1500:5	8000:5
75:5	400:5	2000:5	–

(d) The 5 amps rated secondary is IEEE standard as well as USACE hydropower standard. Other rated secondary currents (1 amp or 2.5 amps) are available for special applications, particularly under IEC standards, but should not be substituted here.

(5) The continuous CT thermal rating is a measure of how many primary amperes the CT can carry over its primary rating based on a 30 °C average ambient air temperature without exceeding the required temperature rise and accuracy.

(a) IEEE C57.13 traditionally recognized thermal rating factors between 1.0 and 4.0. Hydroelectric powerhouse practice is to require a thermal rating factor of 1.33, meaning the CT can operate continuously without overheating while 133 percent of primary current flows through it (for example, 2,660 amps through a 2,000:5 CT). This is to guard against accumulated heat damage from occasional high or sustained overcurrents. Higher thermal rating factors are much more expensive and should not be required if the ratio is properly selected, since most USACE generators are typically not subject to routine high or sustained overcurrents.

(b) The short-time thermal current rating of a CT is the rms symmetrical primary current that can be carried for one second with the secondary winding short-circuited without exceeding the limiting temperature in any winding.

(6) CT wiring configurations must be shown on the one-line or three-line diagrams in the contract drawings.

(a) Ratios should use a colon (:) for consistency with IEEE standards.

(b) CTs are usually wired in a wye configuration, such that their secondaries (which run to the meters and relays) have a common neutral. Wye or grounded-wye graphic symbols are sometimes shown at CTs on one-line or three-line diagrams. Some older transformer protection schemes have CTs connected in delta on the high side windings of the step-up transformer. Older excitation schemes may still use just one CT located on the B-phase of the generator lead.

(c) Metering does not require CT input from all three phases, whereas differential relaying does. Transformer differential protection using all electromechanical relays on delta-wye transformers have their CTs wired in the opposite configuration (wye-delta) to make the relay function. Digital relays have more versatility.

(d) Each differential relay must have its own dedicated paired set of CTs, one set on each side of the device being protected; otherwise, a non-differential-related disturbance on one set of CTs might trick the differential relay into sensing a difference between the other set of CTs and cause a nuisance trip of the system.

(e) A single CT has traditionally been used on the B-phase for input to a generator exciter, but modern digital exciters with power system stabilizers usually require three CTs (one per phase).

(f) Two CTs may be used for metering or relaying (usually on A-phase and C-phase) in what is called a “vee” configuration, but USACE hydropower practice is to use three CTs if space allows.

(7) Installation of CTs for isolated-phase bus systems is typically in line with the isolated-phase bus at a point near the generator terminals or generator breaker. These take the form of 600-volt rated window-type CTs in an enclosure built into the bus housings. VT cubicles for isolated-phase bus systems do not include CTs because the CTs are typically within the isophase bus as window CTs around the bus conductor. VT cubicles are typically adjacent to the surge protection equipment cubicle. VTs and surge

arresters are shunt devices that need to respond only to voltage, and they typically take advantage of a common space along the bus for their connections; however, VTs require more maintenance than surge arresters and thus more accessibility, so the surge arresters are usually isolated from the VTs.

(a) Newer generator breakers may also have 600-volt rated bushing CTs (similar to window CTs) on both sides of the breaker, particularly so for drawout breakers. Older breakers may have been built with full-voltage bar-type CTs in the switchgear, which have often been left in service during breaker replacements. New breakers may also employ bar-type CTs if space allows.

(b) Most drawout-type cubicle switchgear designs can accommodate two sets of bushing CTs on both sides of the circuit breaker; however, some horizontal in-line generator circuit breaker designs have room for only one set of bushing CTs on either side of the circuit breaker. In such cases, two-core CTs may be feasible to get two sets of CTs in the space available. But these are expensive, and they must be no larger than the largest single CT that fits inside the breaker, and performance may not be as good as single-core units. Do not confuse two-core CTs with split-core or multi-ratio CTs, they are all different and less sensitive than single-core single ratio CTs.

(c) Generator differential CTs should go on the transformer side of the breaker and on the neutral end of the generator windings. GSU transformer differential CTs should go on the source side of the generator breaker and on the system side of the transformer (addressed in the transformer chapter), so that the breaker is included in each zone of protection.

(d) CTs in the neutral end of the generator windings are usually mounted in the generator air housing.

(e) Metering CTs may go on either side of the generator breaker, but preferably on the source side.

(f) Accessibility for short-circuiting the secondary circuits should be considered in any equipment layout. Terminal blocks where CT secondaries are terminated must have shorting provisions for safety. Lifting a live CT wire from one terminal without the secondaries shorted together could result in very high voltage at the open terminals and possibly an arc flash incident.

(8) Relaying CTs must be able to deliver rated voltage at up to 20 times the normal secondary current during a fault without exceeding a 10 percent ratio correction factor (see IEEE C57.13 for information on the various correction factors). Relaying CTs, especially for differential protection, should also be dedicated to their relaying purpose and not serve double duty as metering CTs.

(9) Relaying accuracy rating or classification is usually represented by a number such as 10, 20, 50, 100, 200, 400, and 800. This value has a prefix of “C” or “T.”

(a) The C is for “calculated,” which indicates that the CT has a low flux leakage and the true performance for any application can be readily determined from the manufacturer’s typical excitation curves. For example, a CT relaying accuracy class C100 means that the ratio error will not exceed 10 percent at any current from 1 to 20 times rated secondary current with a standard 1.0 Ω burden (1.0 Ω × 20 × rated secondary current = 100V).

(b) The T is for “tested,” which indicates that the CT has a high leakage flux and the true performance for any application must be determined from the manufacturer’s test data.

(c) Older versions of IEEE C57.13 defined these ratings differently and may still be found in O&M manuals.

1. “K” class ratings were related to the “knee point” of the performance curves. They are equivalent to C class devices except that the knee-point voltage was specified to be at least 70 percent of the secondary terminal voltage rating.

2. “L” class ratings were for “low internal impedance.” The CT accuracy is applicable within the entire range of secondary currents from 5 to 20 times the nominal CT rating. These are typically wound primary CTs.

3. “H” class ratings were for “high internal impedance.” The CT accuracy applies at the maximum rated secondary burden at 20 times the rated current. The ratio accuracy can be up to four times greater than the listed value, depending on connected burden and fault current. These are typically window, busing, or bar-type CTs.

(d) None of these class ratings agree with IEC ratings, but industry accepts the values shown in Table 9–3 as being equivalent.

Table 9–3
Institute of Electrical and Electronics Engineers/International Electrotechnical Commission relay accuracy ratings

IEEE C57.13	IEC 61689-2
C100	25 VA Class 10P20
C200	50 VA Class 10P20
C400	100 VA Class 10P20
C800	200 VA Class 10P20

(10) Metering CTs should have a current ratio with a primary number closest to, but never less than, the calculated full load current. Include any anticipated future load growth. This provides a secondary current that ranges from 0 amps to 5 amps maximum as load current flows through the circuit breaker. If the ratio is too low, normal load current in the primary will likely overheat the CT and saturate it, which will severely reduce its accuracy. If the ratio is much too high, normal load current in the primary might cause the CT to operate too low in its region to provide a truly accurate response. For example: if continuous full load current is between 290 and 310 amps, select a current ratio of 400:5 instead of rounding to the nearer 300:5.

Chapter 10
Generator Breakers

10–1. General

a. Generator Circuit Breakers. Generator circuit breakers are typically placed in the medium-voltage generator leads between the generator terminals and the GSU transformer. This chapter focuses on medium-voltage circuit breakers connected within the generator leads. The generator voltage and capacity rating, and the results from fault studies determine the type of generator breaker used, together with its continuous current rating and short-circuit current rating.

b. Unit Connected Generators. Unit-connected generators connect directly to the GSU transformer without a circuit breaker. Unit-connected installations may or may not have a disconnect switch in the generator leads for isolation, but the circuit breaker for the generator is provided only from the high-voltage circuit breaker on the high-voltage side of the GSU transformer. In either case, the breaker is used to interrupt the circuit between the generator and the load under normal operating conditions and during fault conditions.

c. Interrupter Types. Both vacuum interrupters or sulfur hexafluoride gas (SF_6) interrupting mediums are permitted. SF_6 interrupters are better suited for very high fault currents. For SF_6 circuit breakers, special care and handling is needed for SF_6 gas.

d. Obsolete Interrupters. Magnetic, air-blast, and oil interrupters are obsolete and are increasingly difficult to maintain. These should be replaced with new breakers or with retrofills using vacuum or SF_6 technology when encountered.

e. Generator Circuit Breaker Standard. Breakers built specifically for large generator applications have an additional and more stringent standard that may override some of these requirements, as in IEC/IEEE 62271-37-013. This standard was previously just IEEE C37.013 but was withdrawn and should no longer be used. It was incorporated in the joint IEC/IEEE standard 62271-37-013 with refinements.

10–2. Switchgear Types

a. Metal-Enclosed Switchgear. ME switchgear is built to the requirements of IEEE C37.20.3 using breakers with either SF_6 or vacuum interrupters. ME switchgear breakers may be either drawout type or fixed type.

(1) In drawout-type switchgear, the entire breaker can be “racked out” from the switchgear and thus disconnected from the switchgear bus, so that the breaker can be removed without de-energizing the entire switchgear lineup. The breaker literally plugs into and out of sockets connected to the bus. In the drawn-out position, the breaker is visibly isolated from energized bus.

(2) In fixed-type switchgear, all breakers remain connected to the bus (bolted connections) and removal of any breaker requires the entire switchgear lineup to be de-energized. ME switchgear with fixed breakers must include an isolating switch with visible contacts to isolate the breaker from the bus. Most large stand-alone generator breakers are fixed type, as there are no other breakers connected to the bus, and BIL ratings of 110 kV are more readily available.

b. Metal-Clad Switchgear. MC switchgear is built to the more stringent requirements of IEEE C37.20.2, such as including more internal barriers and shutters covering energized parts when a breaker is withdrawn from the enclosure. This change makes them preferable in powerhouses over ME switchgear of equivalent ratings built to IEEE C37.20.3 requirements, except that most available drawout breakers are limited to 95 kV BIL.

10–3. Circuit Breaker Classes

a. IEEE C37.04 and C37.06 define Class S1 and Class S2 circuit breakers and their associated ratings.

b. Class S1 breakers (previously known as “distribution class”) may be drawout type under C37.20.2 (metal-clad), or either fixed type or drawout type under C37.20.3 (metal-enclosed). Class S1 breakers are intended for systems where the ratio of system reactance “X” to the system resistance “R” (the X/R ratio) is less than 17. In such systems, the relatively lower DC offsets and transient response during a short circuit event allows the system to revert to normal more quickly. Delayed current-zero crossings (where the current sine wave goes from positive to negative or vice versa) and arc extinguishment occurs within the interrupter anywhere between 3 to 8 cycles for a 60-Hertz system with an X/R ratio less than 17. Typical Class S1 voltage ratings include:

(1) 5kV, 60 kV BIL.

(2) 15kV, 95kV BIL.

c. Class S2 breakers (previously known as “station class”) are predominantly fixed type under IEEE C37.20.3 (metal enclosed) and are intended for systems with an X/R ratio well in excess of 17, which is typical at the terminals of generators in excess of 10 MVA. Such systems have much higher DC offsets and longer transients during a short-circuit event. Current-zero crossings for all phases and arc extinguishment within the interrupter may not occur for as much as 2 seconds (120 cycles). This could destroy breakers not designed for this application. The voltage rating applicable for Class 2 breakers in USACE powerhouses is:

(1) 15.5 kV, 110 kV BIL, under IEEE C37.04 and C37.06.

(2) Higher ratings are available under the IEC/IEEE 62271-37-013.

(3) Lower voltage systems are limited to Class S1 breakers.

d. Class S1 and Class S2 breakers that are to be used as main unit generator breakers must also meet the applicable requirements of IEC/IEEE 62271-37-013.

10–4. Considerations for Selecting a Generator Breaker

There are many considerations for selecting the best type of breakers for protecting and switching of generators. See Table 10–1 and the following discussion for guidance.

a. Become familiar with IEEE C37.04, C37.06, C37.010, C37.20.2, C37.20.3, and IEC/IEEE 62271-37-013 for a better understanding of the ratings discussed here. Any anticipated unusual service conditions identified in IEEE C37.010 should be brought to the attention of the breaker manufacturer in the specifications.

b. The electrical ratings of the generator, including any continuous overload rating and operation at rated power factor, should be used to determine the required continuous current capability of the breaker.

Table 10–1
Selecting a generator breaker based on system voltage, maximum current, and basic impulse level[a]

Upper Limit Generator Application, MVA	USACE System Voltage, kV	Breaker Voltage Rating, kV	Maximum Continuous Current, A	Impulse Rating (BIL), kV	Maximum Short-Circuit Current Rating, kA	Breaker Type	Interrupting Medium
29	4.16 or 4.2	4.76	4,000	60	63	Drawout (Class S1)	Vacuum
35	6.9	8.25	3,000	95	40	Drawout (Class S1)	Vacuum
47	6.9	15.0	4,000	95	63	Drawout (Class S1)	Vacuum
71 (75)	13.8 (14.4)	15.5	3,000[b]	110[b]	40	Fixed (Class S2)	Vacuum
95 (99)	13.8 (14.4)	15.0	4,000[b]	95[b]	63	Drawout (Class S1)	Vacuum
119 (124)	13.8 (14.4)	15.8 or 17.5	6,000	110	63[c]	Fixed	SF_6
179 (187)	13.8 (14.4)	15.8 or 17.5	7,500	110	63[c]	In-Line Isophase	SF_6

Note:
[a] Table 10–1 is based on IEEE C37.04, C37.06, C37.20.2, and C37.20.3. This table is not all inclusive and omits some combinations offered by manufacturers adhering only to IEC/IEEE 62271-37-013.
[b] IEEE C37.06 limits 110 kV BIL Class S2 breakers to 3000 amps, while 95 kV BIL Class S1 breakers go up to 4000 amps. IEC/IEEE 62271-37-013 ampacity ratings are open to interpretation, but most manufacturers follow these limits for matching ampacity ratings to BIL ratings for vacuum switchgear.
[c] According to other IEC standards referenced by IEC/IEEE 62271-37-013, several manufacturers offer short-circuit current ratings over 100 kA for these types of generator breakers.

c. Some manufacturers now offer 15 kV-rated drawout generator breakers with vacuum interrupters that meet legacy IEEE C37.013 requirements up to 7,000 Amps continuous and 75 kA short circuit; however, these are still limited to 95 kV BIL. SF_6 interrupters are recommended for such high continuous currents and short-circuit currents.

d. System parameters (fault current contributions) and generator impedance are required to determine the required short circuit rating.

e. Breaker manufacturers may provide capacitors to meet TRV requirements even if not specified. This is provided by capacitors that prevent the rapid rate of rise of recovery voltage across a just-opened breaker from exceeding the breaker’s recovering dielectric strength to prevent an internal breaker flashover.

10–5. K-Factor for Breaker Replacements

K-factor is the ratio of the rated maximum voltage to the lowest operating voltage for which the inverse relationship between the operating voltage and the interrupting current holds true. It is a limit for derating the interrupting current for a varying operating voltage. K factors between 1.1 and 1.5 were common during construction of existing USACE powerhouses. The K-factor has since been retired from IEEE C37.06.

a. K-factors were associated with breaker short-circuit capacity expressed in terms of MVA. Modern short-circuit capacity is expressed in terms of kA.

b. All new breaker designs are required to have breakers manufactured for fully rated short-circuit performance based on a K factor of 1.0, with no deratings allowed.

c. Some replacement breakers (legacy designs) are still on the market and have K factors greater than 1.0 to facilitate matching the nameplate of an obsolete breaker that requires replacement; however, the desired method to specify a replacement breaker is to verify short-circuit conditions and select ratings based on a K factor of 1.0 regardless of the K factor of the existing breaker being replaced.

d. The available short-circuit current for all plants at any voltage rating must be verified and checked against the latest standards when specifying breakers, rather than just matching existing nameplates on breakers being replaced.

e. If available short circuit current exceeds IEEE C37.06 limits for a given voltage rating, the next highest voltage rating may be required. For example, a plant built with legacy 7.2 kV-rated breakers having a K-factor of 1.3 may now require 15 kV-rated breakers to get acceptable fully rated short circuit current capability.

10–6. Breaker Configurations

Circuit breakers are furnished in factory-built steel enclosures in one of three basic configurations. Each type of circuit breaker has specific applications depending on current ratings and short-circuit current ratings. Either vacuum interrupters or SF_6 interrupting mediums are permitted.

a. MC switchgear with drawout-type standard circuit breakers can be used for generator switching using Class S1 breakers. These are often used in switchgear lineups alongside the station service breakers, sharing the same bus. See Figure 10–1 for an example.

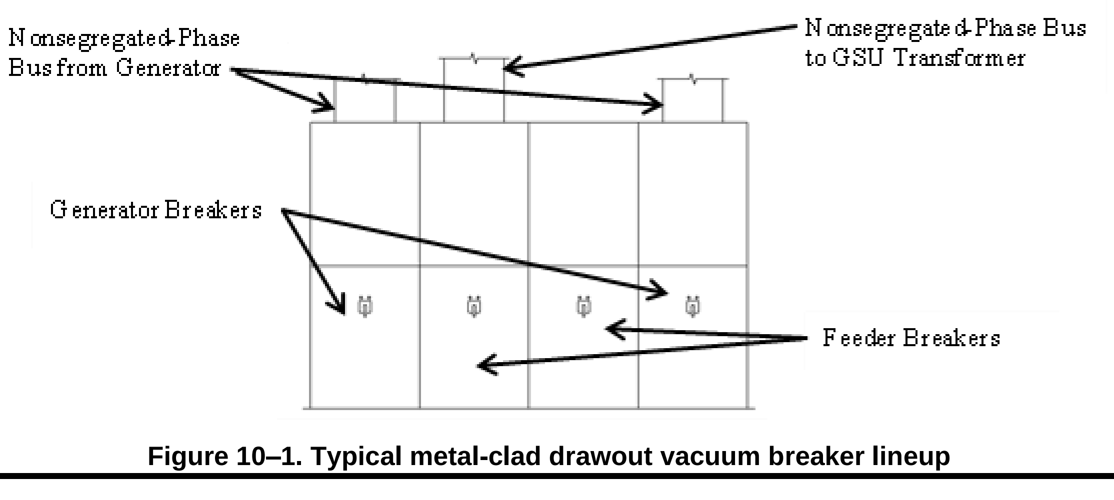


Figure 10–1. Typical metal-clad drawout vacuum breaker lineup

(1) Vacuum interrupters are more typically available and somewhat less expensive than SF_6 interrupters for use in MC switchgear.

(2) Most vacuum circuit breakers are available up to 3,000 amps, but some manufacturers have options available for forced-air cooling on 3,000 amp breakers (for example) to allow rated operation at 4,000 amps if the switchgear bus is rated that high. Other combinations of enhance ratings may be attained depending on the manufacturer. Loss of ventilation in such cases must be alarmed, as it essentially de-rates the breaker to its default non-fan-cooled rating.

(3) The maximum preferred ratings per IEEE C37.20.2 for 15kV rated MC switchgear are 4,000 amps and 95 kV BIL. For applications that require ratings above 4,000 amps and/or 95 kV BIL, using ME switchgear as described in paragraph *b*. below is recommended.

b. ME switchgear with fixed-type, generator-rated circuit breakers can be used in generator switching using Class S1 or Class S2 circuit breakers. Class S2 breakers are usually stand-alone, high-amperage breakers located near the generator terminals and connected by isolated-phase bus. See Figure 10–2 for an example.

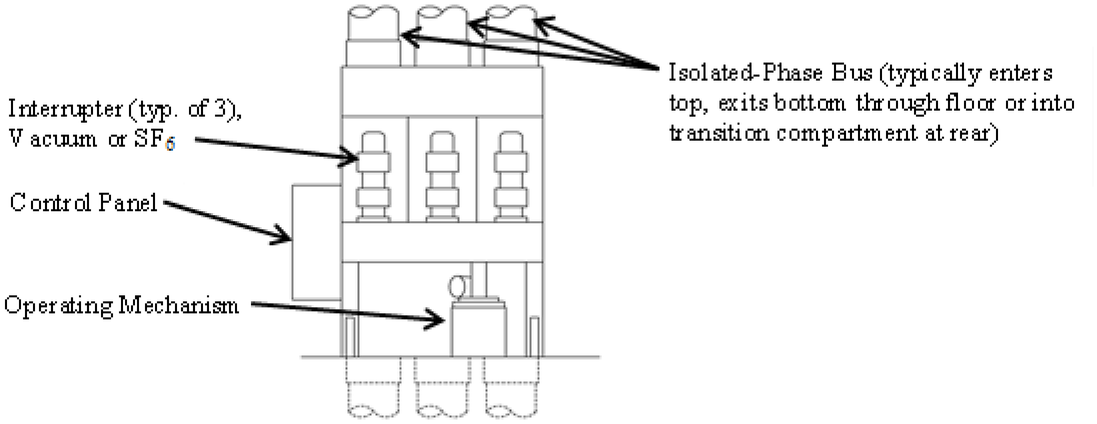


Figure 10–2. Typical fixed generator breaker (shown with front removed)

(1) Vacuum or SF_6 interrupters may be used, but SF_6 is typical due to higher continuous current and interrupting capability.

(2) Older air-blast breakers may be replaced entirely with a new breaker, but many have been retrofilled (defined by IEEE C37.59 as a conversion process that includes replacing the circuit breaker and circuit breaker compartment) with SF_6 breakers to reduce cost by incorporating the existing bus and enclosure into the breaker manufacturer's retrofill design.

(3) When retrofilling an existing air-blast breaker having internal bus disconnect switches for isolating the breaker, the disconnect switches may or may not remain in place depending on the breaker manufacturer's retrofill design. If existing internal disconnect switches cannot be retained or replaced by the retrofill design, then external means of isolating the breaker must be considered.

c. In-line, isolated-phase bus breakers are available for generator breaker applications 5,000 amp or higher, although installation as a breaker replacement requires extensive modification of the existing isophase bus system. No USACE powerhouse was originally designed around horizontal in-line isophase bus/breakers, although at least one such breaker replacement was accomplished on a powerhouse roof where space was available to connect into the existing isophase bus. Horizontal in-line breakers have parameters exceeding IEEE C37.04 and C37.06 and thus are designed instead to comply with IEC standards. In-line breakers are mounted in the isolated-phase bus system horizontally and have separate housings for each phase, all connected to a common operating mechanism. See Figure 10–3 for an example.

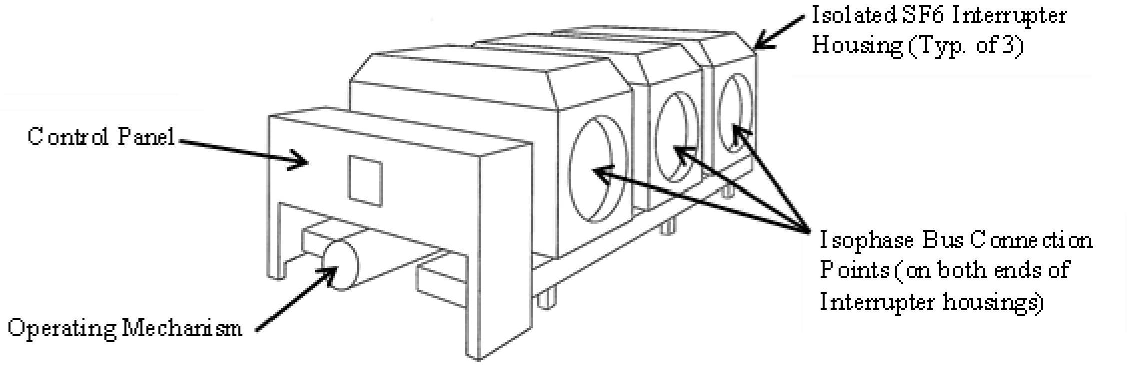


Figure 10–3. Typical in-line generator breaker

(1) These breakers exceed IEEE C37.06 requirements. The specifications should refer instead to IEC/IEEE 62271-37-013.

(2) In-line breakers primarily use SF_6 interrupters.

(3) Breaker isolating switches are typically designed into the breaker compartment.

(4) In-line breakers may not have sufficient room for the number of CTs required. Dual-core CTs may be required to meet all needs. See Chapter 9 for additional information.

10–7. Generator Breaker Protection

Generator circuit breaker protection schemes are beyond the scope of this chapter, but a breaker failure scheme should always be considered for generator breakers. If a generator breaker fails to open when excitation is removed and a unit is supposed to shut down, the spinning unit may begin functioning as a motor driven by the connection to the grid through the generator breaker. This can quickly cause severe overheating and damage to the winding and other generator components.

Chapter 11
Generator Step-Up Power Transformers

11–1. General

GSU power transformers are the critical electrical link between the powerhouse generating equipment and the connected transmission system. A GSU transformer not only transforms power from the medium-voltage of the generators to the high-voltage transmission level, but also provides protection to the powerhouse equipment from system fault current events via its internal impedance and configuration of the winding connections.

11–2. Design

a. *Type*. GSU transformers designed for hydropower facilities are usually classified as Class II power transformers as defined in IEEE C57.12.00. Class II power transformers have high-voltage windings rated 69 kV or higher, and power ratings greater than 10,000 kVA single-phase or 15,000 kVA three-phase.

b. *Transformer Construction*. The two types of internal construction used for GSU transformers are core form and shell form. Core form transformers are more widely used due to their simple design and lower manufacturing costs as compared to the shell form type. Due to the design characteristics of shell form transformers, they are typically heavier, more compact, have greater mechanical and short-circuit strengths and may be transported on their side to reduce the overall shipping height. Shell form transformers are primarily used for EHV applications where shipping dimensional restrictions are present. Both forms of construction are permitted for USACE installations.

c. *Phasing*. GSU transformers may be of a three-phase construction or consist of three single-phase transformers connected to form an electrically equivalent three-phase bank. Single-phase transformers configured in a three-phase bank are selected when site or transportation restrictions do not allow a three-phase construction, or the MVA of the transformers is too large for a single three-phase bank. Although less common, a single-phase transformer bank can also be configured to match the phase connections between the powerhouse and transmission system when the high-voltage line phase connections are non-standard. This is accomplished by making non-standard delta connections external to the single-phase transformer bank to match the high-voltage line phasing to maintain the proper phase shift through the transformers. Using a standard three-phase transformer for this scenario could result in a non-standard phase shift in the transformer itself.

(1) *History*.

(a) Many original GSU transformer installations at USACE hydropower projects use banks of single-phase transformers. This was often due to shipping limitations at the time the transformers and powerhouse were built. Many facilities are in mountainous areas where surveying identified an ideal area to create a reservoir and were served by a rail spur at the time of construction. Transformers constructed as shell form can be rotated 90 degrees onto their side for shipping, allowing passage through minimum height tunnels. In the event of over-the-road shipping, it was difficult to build the assemblies or provide the tractor to transport a large three-phase transformer. Modern

highway infrastructures typically allow a combination of rail as well as over-the-road truck transport that reduces these restrictions.

(b) In addition to these physical restrictions, original design memoranda indicated concerns at the time with sufficient, reliable operating history of large three-phase transformers of the required size.

(2) *Reliability*. Assuming that transformer failures in a bank of three single-phase units are mutually exclusive, failure probabilities are additive. Transformers may fail for any number of reasons, but each tank has the same probability of failure—meaning that one three-phase transformer has essentially the same probability of failure as one single-phase transformer. The tradeoff on this is return-to-service in the event of failure. The cost to purchase and retain a single-phase spare is lower than for a three-phase spare. In critical, high-revenue plants, the cost of a failure may far exceed the cost of having a spare, and the choice could be made to retain a single-phase spare to mitigate that cost risk.

(3) *Capital Costs*.

(a) The lowest capital cost configuration is for three-phase transformers. From a manufacturing standpoint, each single-phase transformer requires its own tank, monitoring systems, cooling systems, and internal appurtenances to support the winding. Due to the magnetic design, three single-phase transformers also require significantly more magnetic steel per MVA than a three-phase due to less efficient use of magnetic steel due to all the windings not being on a common core. Thus, the cost per MVA of total output is always higher for any single-phase construction.

(b) The capital costs do not end at the transformer supply. Each transformer tank requires installation in a containment vault, associated wiring, and the associated labor. Space limitations often require that single-phase transformers be much closer together. Transformers installed with insufficient separation may require additional fire protection features per Unified Facilities Criteria (UFC) 3-600-01.

(4) *Insulating Oil Requirements*.

(a) For oil-filled transformers, each active transformer assembly requires oil to insulate the phase windings and the winding-to-tank space on the tank interior. Placing three phases in one tank reduces the phase-to-phase clearance required compared to single phase construction. Due to this physical requirement of construction, a single-phase bank of transformers of equal rating to a three-phase transformer contains more total oil. A three-phase bank of single-phase transformers will contain approximately 30 percent more oil than an equivalent voltage and MVA rating single three-phase transformer.

(b) The lower oil volume of a three-phase bank reduces the installed costs by also reducing the amount of oil containment space required for each area, in addition to the less restrictive firewall requirements.

(5) *Recurring Maintenance Costs*. While three single-phase transformers combine to do the same “work” as one three-phase unit, from an operations and maintenance perspective, it nearly triples the amount of annual effort in labor and cost. Each transformer tank requires its individual protective and safety mechanisms—all of which need to be checked and maintained regularly. Maintenance and test personnel need to move their equipment from one transformer to the next, substantially increasing the amount of time it takes to test the same number of items on a three-phase transformer.

Each transformer comes with a control cabinet to operate the transformer cooling systems and relay status back to the powerplant with individual components that need to be stocked, checked, and replaced throughout their life cycle.

d. Phase Relation. The standard phase relation for GSU power transformers is a wye-delta connection (wye connection for the high-voltage windings, delta connection for the low-voltage windings). This phase relation and winding connection method prohibits the transmission of zero-phase sequence fault currents from the system into the powerhouse. Three single-phase transformers connected as a three-phase bank use the same phase relation, with the delta connections made at the medium-voltage bus external to the transformer.

e. Insulation Systems. Insulation systems consist of the solid insulation between the energized conductor and grounded components and the fluid or gas circulating through the transformer. In addition to the conductor solid insulation, three types of oil or gas insulation systems are used in USACE GSU power transformer applications.

(1) Mineral oil is a petroleum-based insulating and cooling medium. Mineral oil should meet ASTM D 3487 standards. Acceptable characteristics for use in transformers are defined in IEEE C57.106. Mineral oils that are refined from predominately naphthenic crude oils and meeting the applicable standards are acceptable. Use of paraffinic crude oil derivatives for refill must be checked with the original transformer manufacturer if it is not explicitly specified in the equipment manuals. Mineral oil is typically used with windings that use cellulose or aramid fiber solid insulation surrounding the conductors.

(2) Ester oils are a naturally or synthetically derived insulating and cooling medium. All ester oils must meet ASTM D 6871 standards. Acceptable characteristics for use in transformers are defined in IEEE C57.147. Esters may be selected for biodegradability, less-flammable fluid classification, and oxidation protection for use with cellulose insulation. Using a transformer filled with a less-flammable fluid may allow siting benefits under UFC 3-600-01. Naturally, derived esters must be especially protected from oxidation by contact with atmosphere. Ester oil is typically used with windings that use cellulose or aramid fiber solid insulation surrounding the conductors.

(3) SF_6 is a fluoride gas used as an insulating and cooling medium. SF_6 gas must meet ASTM D2472 standards. Acceptable characteristics for use in transformers are defined in IEC 60076-15. SF_6 transformers are selected for being explosion-proof and fire-proof with no containment or active fire protection requirements. SF_6 is typically used with windings that use polyethylene terephthalate (PET), polyethylene naphthalate (PEN), or polyphenylene sulfide (PPS) solid insulation surrounding the conductors.

f. Oil Preservation System. The two types of oil preservation systems preferred for use with liquid-cooled power transformers are as follows:

(1) *Inert Gas Pressure System*. This method of oil preservation maintains a space above the insulating oil within the transformer tank pressurized with nitrogen, preventing air and moisture from contacting the oil. Nitrogen pressure is maintained within the tank between 0.5 and 5 psi (3.4-34.5 kPa) by a nitrogen regulator system, which is typically housed in a cabinet mounted on the transformer tank, consisting of high-pressure nitrogen cylinders and two-stages of pressure regulators. A nitrogen gas generation system can also be implemented to supply nitrogen to multiple transformers in lieu of

having nitrogen cylinders located at each transformer. The advantages and disadvantages of an inert gas pressure system are listed below.

(a) Advantage: Very effective at preventing atmospheric air and moisture from entering the transformer tank. There are numerous examples of transformers with this design in operation for over 60 years, maintaining purity of the transformer oil.

(b) Advantage: Provides oil preservation for the life of the transformer with no required maintenance of transformer components that require an extended outage. If maintenance is required for the nitrogen regulator system, the individual components can be procured "off-the-shelf" from many sources.

(c) Disadvantage: Nitrogen gas is a consumable for this type of preservation system, and high-pressure nitrogen cylinders require replacement frequently over the life of the transformer. Depending on the loading and operational characteristics of the transformer, leaks, and the ambient temperature conditions where the transformers are installed, a cylinder typically lasts from 6–12 months.

(2) *Air-Cell, Constant-Pressure, Reservoir Tank System*. This method of oil preservation consists of a reservoir tank with an internally suspended bladder, which is typically mounted off to the side of the transformer and above the tank cover with interconnecting piping. The bladder expands and contracts following the oil expansion and contraction due to changes in main tank oil operating temperature and isolates the oil from the atmosphere. The interior of the bladder is connected to the atmosphere through a dehydrating breather, which allows the diaphragm to breathe during the expansion and contraction process and keeps the top of the transformer oil at atmospheric pressure. The advantages and disadvantages of this type of system are listed below.

(a) Advantage: Reduced maintenance in that there are no nitrogen bottles to replace.

(b) Advantage: When a Buchholz relay is added to the piping between the reservoir tank and the transformer tank, there is an additional low oil level float that can be used as a backup to the regular oil level gauge mounted on the reservoir tank.

(c) Disadvantage: The reservoir tank can add as much as 500 gallons of oil to the overall volume as compared to a nitrogen-blanketed transformer of the same rating, which increases the size of the oil containment required.

(d) Disadvantage: The reservoir tank can add as much as 6 ft (1.8 m) of overall oil-filled height to the transformer as compared to a nitrogen-blanketed transformer. This additional height requires the transformer vault firewalls (if required) to be at least 6 ft (1.8 m) taller.

(e) Disadvantage: Presently, the operational life of the reservoir bladder is 15 to 20 years, at which time the oil must be drained from the reservoir tank, the reservoir tank opened, and the bladder replaced. The replacement bladders may need to be custom manufactured to fit the reservoir tank.

(f) Disadvantage: The interior of the bladder should be inspected for leaks at a minimum of every 3 years, which must be performed during a transformer outage.

(g) Disadvantage: Using a reservoir tank requires adding vent piping from all locations above the tank cover (such as bushing turrets) for routing to the main pipe connection to the reservoir tank. This vent piping, as well as the main pipe connection to

the reservoir tank, can have as many as 20 flanged, gasketed connections, each of which is considered a potential location for an oil leak.

g. *Cooling Systems*. The standard classes of transformer cooling systems are listed in IEEE C57.12.00. The selected method of transformer cooling should minimize the complexity of the cooling system and the required future maintenance and monitoring of the components, while providing the necessary transformer cooling. Site conditions, available space and adjacent structures often dictate the type of cooling systems required. Selection and specifications should reflect any station service supply backfeed needs when a plant is not exporting power.

(1) *Stages of Cooling*. The cooling method should implement the minimum number of cooling stages necessary to cool the transformer for the operational configuration of the connected generators. For unit-connected transformers, this may result in a self-cooled transformer with no additional methods of cooling or one stage of cooling. For transformers with multiple connected generators, this may result in more than one cooling stage to reduce the number of operating cooling groups, depending on loading conditions.

(2) *Forced-Oil Cooling*. Circulating the insulating medium with pumps or blowers is considered forced cooling. Forced cooling may be classified as forced with no intentional means of distribution or directed with intentional distribution through the winding. Extra precautions must be taken in designing transformers with greater than 230 kV high-voltage ratings to prevent static electrification, which can create a buildup of charge from high-velocity oil flow and potentially lead to a transformer failure. Some transformer design considerations that can help reduce static electrification include:

(a) Decrease in oil flow velocity.

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

(c) Restrict operation of pumps prior to transformer energization when the oil is cold.

h. *Bushings*. External connections to transformer windings are made at bushings.

(1) *Bushing Characteristics*. Bushings should conform to the requirements of IEEE C57.19.01. For high-current bushings located in bus enclosures, the requirements of C57.19.04 should be met. The voltage rating should correspond to the insulation level of the associated winding.

(2) *Bushing Construction*. Oil-filled capacitively graded bushings with porcelain insulators have historically been used for high-voltage and high-voltage neutral bushings, however, modern technology dry-type, capacitively graded, resin-impregnated synthetic (RIS) bushings with rubber or silicon insulators are recommended for use whenever possible. Type RIS bushings have significant safety and operational advantages over the oil-filled design, however, using oil-filled or bulk-type bushings may still be necessary for high-current applications.

(3) *Enclosures*. Where the low-voltage bus connections to the transformer bushings are a ME design, a bushing enclosure is included at the transformer to maintain the basic impulse insulation level rating of the connected bus. The air temperature within the bushing enclosure can exceed the 40 °C maximum, and the connected bus can exceed the 70 °C maximum, as specified by IEEE. These elevated operating temperatures create thermal stresses on the bushings and gasket seals, and greater oil expansion for oil-filled bushings. Bushings used for this application should be

rated for operation at elevated temperatures, use materials rated for temperatures up to 200 °C, and, for oil-filled bushings, be designed for higher temperature oil expansion.

11–3. Electrical Characteristics

a. Voltage. Voltage ratings and ratios should conform to IEEE C57.12.00 preferred ratings whenever possible. The selection of voltage ratings should be coordinated with the load flow analysis of the transformer and connected powertrain. Note that for GSU transformers, the primary windings are the low-voltage windings connected to the generators, and the secondary windings are the high-voltage windings connected to the transmission system.

(1) *Secondary Voltage*. The secondary voltage rating should be suitable for the voltage of the transmission system to which it will be connected, with 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) *Primary Voltage*. For transformers 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 provides further guidance on considerations in evaluating suitable voltage ratings for the GSU transformer.

(3) *Maximum Megavolt-Amperes 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 rating of the connected generators.

b. Impedance. Transformer impedance 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. Transformer impedances should be determined considering impacts on selection of the interrupting capacities of station breakers and on the ability of the generators to aid in regulating transmission line voltage. This determination is based on the results of the system and plant fault studies, as well as the power plant load flow analysis. Table 11–1 illustrates the range of impedance values available in a normal two-winding transformer design (values shown are for GSU transformers with a 13.8 kV primary winding).

c. Tap and Voltage Selection. Transformer taps allow a range of voltage ratios to adjust for electrical grid voltages available at the high side of the GSU. GSU transformers typically use a de-energized tap changer (DETC) in the high-voltage winding. A standard DETC setup is five steps of 2.5 percent each. The nominal tap is often the middle value with two steps above and two steps below.

Table 11–1
Nominal design impedance limits for power transformers (percent)

Nominal System kV	Winding BIL kV	Class ONAN, or Self-Cooled Rating of Class ONAN/ONAF, or Class ONAN/ONAF/ONAF		Class OFAF	
		Minimum	**Maximum**	**Minimum**	**Maximum**
15	110	5.00	7.50	8.34	12.50
25	150	5.00	7.50	8.34	12.50
34.5	200	5.25	8.00	8.75	14.33
46	250	5.60	8.40	9.34	14.00
69	350	6.10	9.15	10.17	15.25
115	450	5.90	8.85	9.84	14.75
138	550	6.40	9.60	10.67	16.00
161	650	6.90	10.35	11.50	17.25
230	825	7.50	11.25	12.50	18.75
500	1425	10.95	15.60	18.26	26.00

d. *Basic Lightning Impulse Insulation Levels*. The transformer winding insulation design is based on the specified BIL rating, which provides the transformer the ability to withstand system surge voltages. The impacts of BIL ratings on the transformer design include the winding lead structure and clearances, assembled winding clearances, electrical stresses to ground, and insulation of the winding neutral. The BIL rating is related to the nominal system operating voltage, as listed in IEEE C57.12.00. Multiple recommended BIL levels are provided in the standard for each system voltage to account for connected systems that operate at higher maximum operating voltages that may be subjected to a high number of impulses, and to allow a tradeoff between lower costs and more conservative design assumptions.

11–4. Studies

The following studies should be performed during the design of a power transformer to assure the nameplate ratings are properly coordinated with the connected power plant and system.

a. *Fire Protection and Insulation Selection Study*. All new installations must meet the requirements of Chapter 21. A comparative study of the three insulation systems should be performed with respect to the total cost of installation.

b. *Fault Study*. A fault study is performed to calculate the maximum system fault currents and determine the minimum required transformer impedance to provide protection to the connected powerhouse equipment. This information is then used in the load flow analysis to size the impedance to allow optimal generator MVAR transmission to the system without compromising fault current protection.

c. Load Flow Analysis. The purpose of a load flow analysis is to determine the best transformer voltage ratings, impedance rating, and tap positions based on the connected powertrain. To accomplish this, multiple case simulations are performed by varying the system voltages, transformer ratings, and generator MVAR setpoints. The recommended transformer nominal ratio, tap range, and final tap setting allows the maximum range of generator MVAR transmission to the system without exceeding generator voltage limitations.

d. Loss Valuation Study. Transformer losses represent a considerable economic loss over the life of the power plant. A loss valuation study should be performed to determine the present value of transformer load and no-losses based on a 45-year transformer lifespan, predictions of future power plant operation, and the regional energy value. The resultant values for load and no-load losses expressed in $/kW are used in evaluating proposals that have guaranteed losses that are lower than the maximum values required in the specifications. IEEE C57.120 provides further guidance on transformer loss evaluation.

e. Regional Ambient Temperatures Analysis. The purpose of this analysis is to determine the historical ambient temperatures in the region of the power plant and at the specific transformer installation location, if available, to determine if there are any temperature-based unusual service conditions. Temperature data is obtained from the Global Historical Climatology Network for the nearest land-based observation station for the lifespan of the power plant. The data is analyzed to determine how often the ambient temperatures exceed the maximum allowable as defined by IEEE C57.12.00, and any necessary adjustments made to the transformer ratings. IEEE C57.92 should be consulted in determining the rating required for overloads or high temperature conditions.

f. Bushing Current Transformer Sizing Study. The purpose of this study is to determine the necessary bushing current transformer (BCT) ratings such that they will not saturate under fault conditions. Analysis of the fault current at the installed BCT location, the BCT ratio and classification, and the secondary burden is used to correctly size each BCT to assure proper operation.

11–5. Accessories

Standard transformer accessories are as included in IEEE C57.12.10. The following accessories provide an enhanced level of design, monitoring, protection, or control.

a. Cooling Control System. An electronic cooling control system provides a higher level of functionality, temperature monitoring and cooling control than standard analog gauges and relays. This system can provide direct fiber optic measurement of winding temperatures, control of cooling groups, monitoring for cooling equipment failures, provision of seasonal settings, and perform oil and winding over-temperature alarm and trip functions.

b. Mechanical Over-Pressure Protection Device. This device, also referred to as a pressure relief device, incorporates a self-resetting, spring-loaded valve to relieve the transformer tank of internal pressure during an over-pressure event. This device should incorporate an integral shroud and directional discharge outlet with connected piping to direct any discharged oil to the base level of the transformer and into a containment pit. This design greatly reduces the possibility of the expulsion of hot oil or gas spray around the perimeter of the transformer during a fault, thus enhancing personnel safety and reducing the risk of uncontrolled oil spreading a fire during a catastrophic event. Large volume transformers with more than 10,000 gallons of oil should have two pressure relief devices located on opposite sides of the cover.

c. Online Monitoring Systems. Online systems are available to monitor abnormal transformer operating conditions. These include:

(1) *Dissolved Gas-In-Oil Analyzer*. An online dissolved gas analysis and moisture measurement system provides a means for continuously monitoring the transformer oil for moisture ingress and incipient fault conditions that generate key dissolved gases. The continuous oil monitoring for key dissolved gases can directly assist the maintenance staff in determining when an internal transformer fault has occurred, help diagnose the severity of the fault, and determine the best course of action to avoid either a forced outage or a catastrophic failure. Sampling transformer oil on an annual or bi-annual basis may not be frequent enough to catch an internal fault condition prior to failure, but an online dissolved gas monitor can increase the likelihood of early fault detection. The type of gases generated during the abnormal transformer conditions are described in IEEE C57.104.

(2) *Electronic Rapid Pressure Rise Monitor*. A standard rapid pressure rise relay incorporates a flexible bellows that is designed to actuate on a rate of pressure rise in the transformer tank, which is an indication of a fault condition. The rate of pressure rise setting is pre-calibrated and not adjustable. An alternative to this device an electronic rapid pressure rise monitor, which detects sudden pressure rises within the transformer oil using pressure transducers. This device has multiple selectable rapid pressure-time curves that can be selected based on site specific conditions, to help avoid false activations.

(3) *Partial Discharge Monitor*. Systems sensing rapid electrical pulses relative to the line voltage sinusoid can detect partial discharges. These systems may be tuned and applied to either the transformer windings or the bushings.

(4) *Acoustical Monitoring*. Monitoring acoustic waves in oil from collapsing bubbles or discharges may indicate discharges in transformer windings. With more than one acoustical monitor appropriately applied, fault locations can be triangulated with expert interpretation.

(5) *Bearing Wear Sensor*. The addition of bearing wear sensors in oil pumps for forced-oil-cooled transformers improves bearing condition monitoring and reduces the risk of an in-service pump failure. An oil pump bearing failure can distribute metal fragments throughout the windings that can result in a catastrophic dielectric transformer failure.

(6) *Bushing Monitor*. Transformer bushing monitors provide continuous online monitoring of bushing power factor and capacitance measurements. The most common bushing failure mechanisms are moisture intrusion due to deteriorated gaskets and loose terminals that results in bushing oil contamination, a breakdown of the insulation system, and partial discharge. These failure mechanisms and insulation deterioration can occur between maintenance testing intervals, and testing may not discover the severity of the problems if they are voltage and temperature dependent sine the conditions during offline testing are different from those when the bushing is in service.

d. Lockout Relay. A transformer trip lockout relay should be provided in the transformer control cabinet. The purpose of this relay is to generate a trip signal to the powerhouse control system in the event of a transformer winding overtemperature, or an activation of the rapid pressure rise relay. Present USACE design standards include the provision of this lockout relay at the transformer so that in the occurrence of a transformer trip the operator must physically inspect the transformer and reset the lockout relay prior to re-energization. This device includes an integral lockout relay trip coil monitoring circuit which is wired to the transformer annunciator.

e. Annunciation. Modern transformers may have many status alarms due to the increased number of monitoring and protective devices. The local transformer annunciator should provide a visual indication of all alarm conditions and be specifically designed for the operational conditions experienced in an outdoor transformer control cabinet. Communication requirements should be coordinated with the existing, or future planned, annunciator systems in the powerhouse.

f. Fiber Optic Winding Temperature Measurement. Direct measurement of temperatures within the winding is possible with embedded fiber optic probes. The probes are placed in a winding spacer with an open design to allow circulation of hot oil across the probe sensor and measure the adjacent copper winding temperature. The probe and the sensing device in the control cabinet need to be coordinated for the technology used in the probe coating.

g. Control and Power Cabinets. Separate control and power cabinets should be provided for isolating the 120V control equipment from the power equipment rated greater than 120V. This separation improves arc flash working requirements for maintenance personnel as well as providing electrical isolation for sensitive lower voltage devices housed in the control cabinet. The cabinets should have weatherproof tempered-glass windows for viewing the status of electronic devices and control switches.

h. Access Ladder. A caged access ladder designed for permanent installation provides access for maintenance and testing. Providing a permanent ladder minimizes exposure to untethered ladders during first installation and first climbs during maintenance.

i. Fall Arrest System. Anchors welded to the transformer cover allow mounting of standard fall protection posts. The posts include swivel attachment points to allow multiple workers on the transformer cover, which helps minimize the tangling of fall protection lines.

11–6. Site Constraints and Considerations

When designing a transformer, the installation site should be inspected, and maintenance personnel interviewed for any past or present operational issues. Consider the economics of design choices and possible solutions to maximize longevity, minimize maintenance efforts and costs, or reduce environmental hazards. Fire protection and containment requirements substantially impact economics and should be coordinated early in the design process. Review access both at the local site and the surrounding region for challenges regarding transformer transportation, including weight restrictions and oversize loads.

a. Layout and Configuration. The transformer layout and configuration should be designed for the installed location with consideration given to the following:

(1) *Cooling Method*. Transformers should be situated so unrestricted ambient air circulation is allowed regardless of the cooling method. Use vertical draft cooling fans when installed in close proximity to walls on more than two sides, or in locations where power plant maintenance operations are routinely conducted adjacent to the transformer fans and consider annual snow accumulation for determining the minimum fan heights. For forced-cooling, mount pumps or blowers at the bottom of the heat exchanger to improve access and maintenance.

(2) Orientation of the transformers for proper interconnection to the low-voltage conductors and incoming high-voltage lines.

(3) Transformer oil preservation system, with consideration given to transformer size, oil volume, and overall height, which affects the size of the firewalls.

(4) Control and power cabinets and other devices that house electronic components should be located on the transformer to minimize direct exposure to sunlight and be accessible to O&M personnel.

b. Maintenance. Transformer devices and ancillary equipment should be designed and oriented with consideration given to future maintenance. Gauges and devices should be easily viewable by an operator performing maintenance inspections and located on one side of the transformer tank as much as possible. Equipment that is heavy and must be lifted by maintenance personnel, such as replacement nitrogen cylinders for the oil preservation system, should be located on, or adjacent to, the transformer to minimize the lifting height.

11–7. Fire Protection

a. See Chapter 21 for fire protection system requirements for transformers.

b. 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 protective measures. Fires in transformers are caused primarily from breakdown of their insulation systems, although bushing failures may 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.

c. When a fire occurs due to overheating and rupturing of an oil-filled transformer that transformer is considered a total loss. All fire protection methods are aimed at preventing migration of heat and flame to adjacent transformers and structures.

11–8. Fire Suppression

See Chapter 21 for considerations regarding transformer fire suppression systems.

11–9. Oil Containment Systems

a. See Chapter 21 for considerations regarding transformer containment and transformer secondary containment.

b. See Chapter 27 for considerations regarding draining of transformer containments. Special provisions (oil-water separators, oil traps, etc.) must be made to allow separation of oil spillage versus normal water runoff from storms, etc.

c. See Chapter 29 for considerations regarding oil spill prevention. 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 valve. The volume of the containment should be sufficient to retain all of the oil from the transformer to prevent spillage into waterways or contamination of soil around the transformer foundations. IEEE 979 and 980 provide additional guidance on design considerations for oil containment systems.

11–10. Seismic Restraint

Transformers should be designed for seismic restraint with the transformer tank structural base welded to embedded steel plates in the mounting pad foundations. Rail mounted transformers should have wheel chocks installed on the railing to restrict transformer movement, and the tank seismically anchored to the pedestals or mounting pad using turnbuckles. Other methods of seismic restraint may be necessary based on specific site installation conditions; however, all seismic anchors and welds for transformer restraint must be designed to comply with American Society of Civil Engineers (ASCE) 7-16 and IEEE 693. See Figure 11–1 for an example of the three-phase GSU transformer layout.

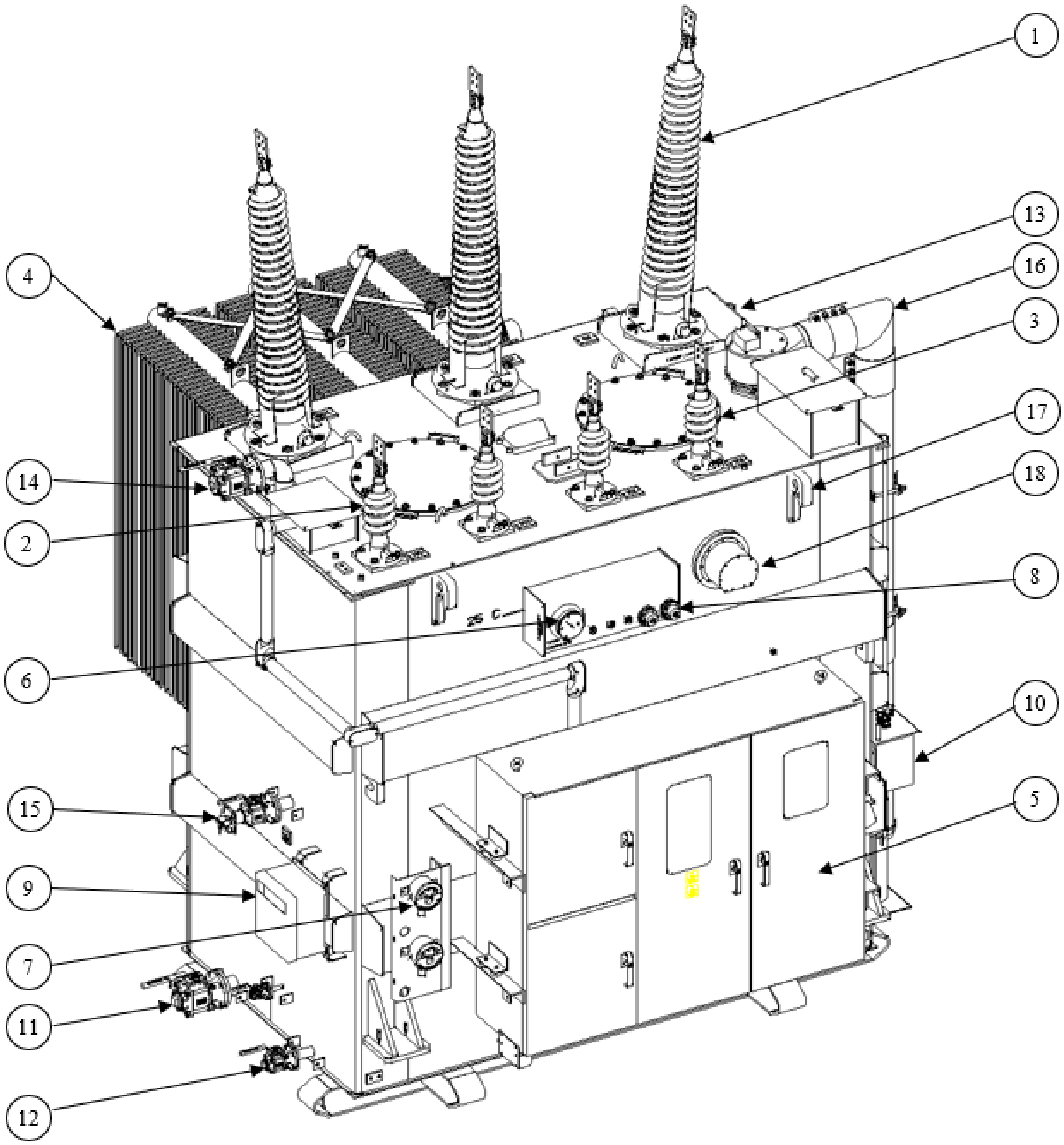


Figure 11–1. Example three-phase generator step-up transformer layout

Legend: Transformer Components for Figure 11–1.

1. High-voltage bushing
2. High-voltage neutral bushing
3. Low-voltage bushing
4. Radiator and cooling fans
5. Control and power cabinets
6. Oil level indicator
7. Analog temperature gauges
8. Thermowells
9. Electronic pressure monitor
10. Gas-in-oil monitoring equipment
11. Main drain valve
12. Lower filter valve
13. Upper filter valve (partially obscured in figure)
14. Vacuum valve
15. Electronic pressure monitor transducer sensors valve
16. Pressure relief device and discharge pipe
17. Lifting eye
18. Fiber-optic winding temperature probes feedthrough plate

Chapter 12
Direct Current and Preferred Alternating Current Systems

12–1. Purpose

a. The general purpose of the DC and preferred AC systems is to provide clean and reliable power to critical protection, control, annunciation, and communication systems while keeping the backup batteries fully charged. In the event of loss of normal station service power, the DC and preferred AC systems provide a battery-backed power source for critical functions such as opening and closing breakers and starting a main unit if necessary to restore a normal source of station power, or to allow starting and transfer to a standby source such as a diesel-driven standby generator. Design considerations and the more relevant standards are provided in paragraph 12–2.

b. The DC system is used for circuit breaker controls, relaying, DC inputs for SCADA, preferred AC inverter, generator exciter field flashing, alarm functions, and emergency lights. The system consists of a storage battery with its associated chargers, providing the stored energy system required to ensure adequate and uninterruptible power for critical powerplant equipment. This system is intended for critical loads only and should not have unnecessary loads added that will reduce the system's backup battery capacity during an emergency.

(1) The DC system should have minimum of three independent power sources, those being the battery bank, and two chargers, each sized for the entire DC load. The system should meet the following criteria.

(2) Battery capacity must be adequate to serve critical plant loads when external power is lost or during periods when plant is isolated or islanded from the grid.

(3) The DC system's function should be limited to providing power and control to those devices that are used to protect or operate the plant or an individual unit. This should include exciter field flashing if starting a main unit is required to restore station service power.

c. The preferred AC system provides 120VAC power to critical systems, such as the station clock, code call system, telephone and critical communications, fire detection and alarms, battery room monitors and detectors, and AC inputs for SCADA. This may also be known at some plants as the essential AC system.

(1) The preferred AC system should have minimum of two independent power sources for the inverter, those being the DC bus for inverter DC input and a normal 120VAC non-battery backed bypass. A static transfer switch is an integral component of an inverter that automatically transfers the inverter input from the 125VDC station battery to the 120VAC bypass source in the event of an inverter failure. The static transfer switch may also be manually operated, or an integral manually operated bypass switch may be provided to switch from the 125VDC source to the 120VAC source; however, these should not be used as a bypass for performing maintenance on the inverter electronics, as some of the buses within the enclosure will still be energized. An external maintenance bypass switch is recommended to totally isolate the inverter from both energized sources.

(2) The system should meet the following criteria:

(a) Inverter capacity must be adequate to serve only critical plant loads when external power is lost or during periods when plant is isolated or islanded from the grid.

(b) The preferred AC system's function should be limited to providing power and control to those devices within the powerhouse that are used to protect or operate the plant or an individual unit. Normal non-essential AC loads must be excluded, as they impact the capacity of the station battery during an emergency.

d. The DC and preferred AC systems should be redundant to reduce the effects of a single point of failure. See Figure 12–1 for an example DC system and preferred AC system single line diagram. In this example, the DC system is truly redundant only if both battery chargers to the station service battery switchboard (SB board) are powered from independent sources, and even then, the single SB board constitutes a possible single point of failure. The preferred AC system is truly redundant only if both inverters are powered from independent DC sources from another SB board; however, the transfer switch constitutes a possible single point of failure. This is a typical configuration found in smaller plants where the station service system usually has a simpler configuration and there is less space for large equipment.

12–2. Design Considerations

The battery and battery circuits should be properly designed, safeguarded, and maintained, and the emergency requirements should be carefully estimated to ensure adequate battery performance during emergencies. IEEE 946 and Electric Power Research Institute (EPRI) EL-5036, Volume 9, provide guidance about factors to consider and evaluate in planning and designing DC systems. IEEE 485 provides guidance on sizing a battery for the system. IEEE 450 provides guidelines and procedures for maintaining and the battery system and testing its capacity. The USBR FIST Volume 3-6 also provides extensive coverage of these topics as well as calculation methods.

12–3. Battery Types

Battery posts and intercell connections should be insulated. The battery should use cells of the vented lead-acid (VLA) type. The sealed valve regulated lead acid type is not recommended due to decreased reliability, shorter useful life, and intolerant overcharging characteristics. The preferred VLA battery has cells using lead or lead alloy plates. Other battery types are available but may not be explicitly covered under NERC Protection and Control Requirements (PRC)-005-2.

a. Cells using pure lead plates (Planté cells) are preferred due to superior life expectancy and long-term performance. These cells are typically larger in dimensions than comparative lead alloy cells.

b. Lead-calcium plates are acceptable where the typically smaller size of lead-calcium cells is required due to space constraints or are more readily available. Lead-calcium cells also tend to be less expensive than Planté cells.

c. Lead-antimony plates are prone to greater hydrogen evolution and are not recommended.

d. Lead-selenium cells exhibit comparative performance to lead-calcium cells but tend to require more maintenance and are thus not recommended.

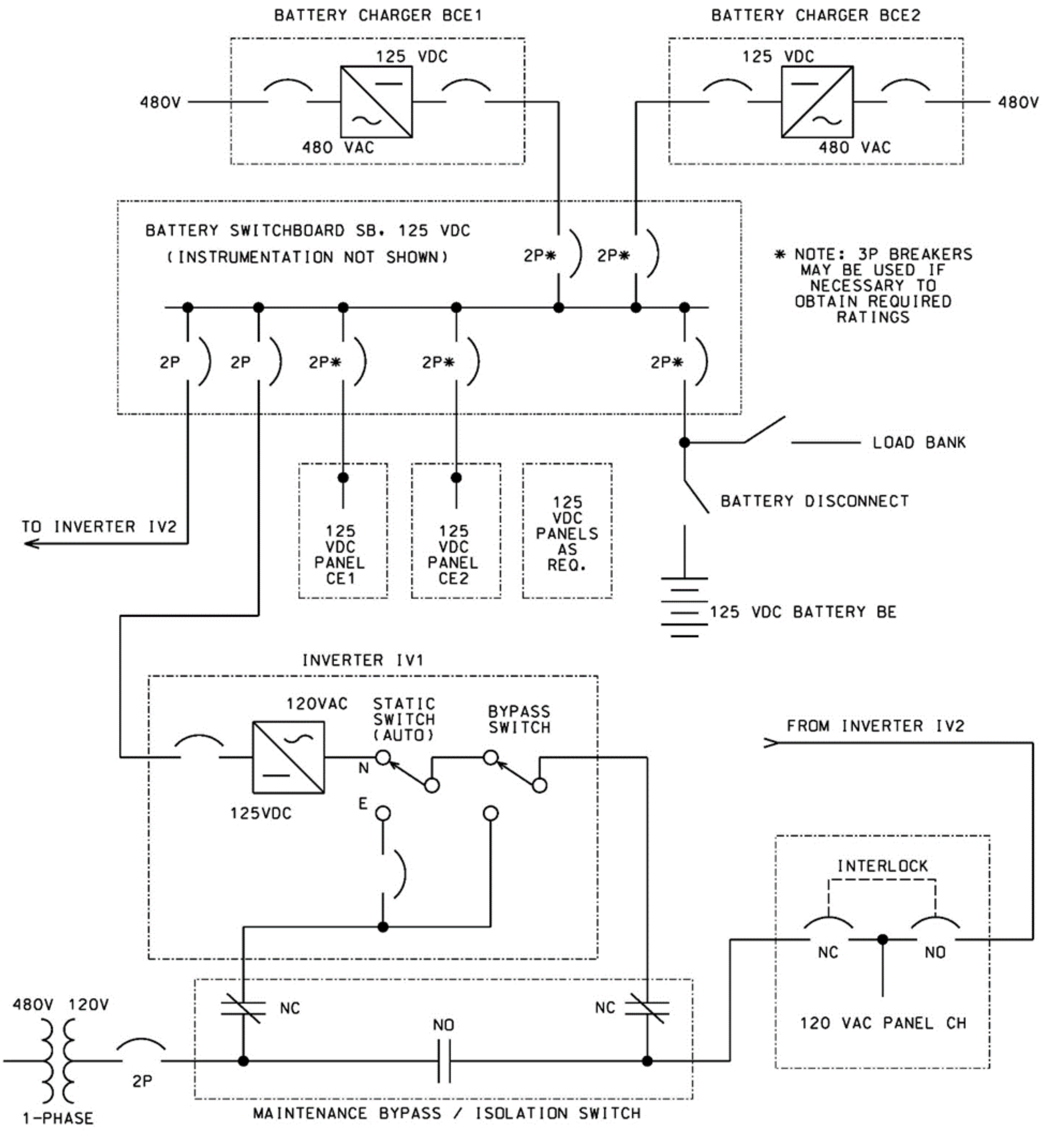


Figure 12–1. Example single line direct current/preferred alternating current system diagram

12–4. Battery Room

A dedicated battery room is highly recommended to provide the required ventilation and sensing of hydrogen concentration in the ambient air. When this is not possible, the battery should be fenced off from the rest of the area. Battery rooms are not considered hazardous locations as defined by the NEC. Battery rooms should not be used for any type of storage unless approved by a Fire Protection Engineer for a specific purpose.

Mechanical and structural designers should be consulted as required for the following considerations.

a. Heating, ventilating, and/or air conditioning should be provided if necessary to obtain full rated performance out of the cells. The desired ambient temperature is 77 °F (25 °C).

b. Battery cells should be mounted in rows on racks rated for the seismic zone of the powerhouse permitting viewing the edges of plates and the bottom of the cells from one side of the battery. The tops of all cells should preferably be of the same height above the floor. The height should be convenient for adding water to the cells.

(1) Tiered arrangements of cells should be avoided to prevent having to reach across an energized row to access a row behind it. If space constraints require more than one row along the same wall, tiered arrangements are preferred. Stacked arrangement of one row above another should not be used.

(2) Aisles should be provided permitting removal of a cell from its row onto a lift or cart without reaching over any other cells. At least a 3-ft (.91 m) clear floor space is required in front of a battery rack for NEC working clearance.

(3) A spill barrier affixed to the floor is required around the racks.

(4) Racks must meet seismic criteria for the geographic location.

(5) Racks must be electrically grounded.

c. Lighting fixtures in the battery room should be of the vapor-proof type, with the local control switch mounted outside by the entrance to the room. Fixtures do not need to be explosion-proof.

d. Battery charging equipment and controls should not be located in the battery room. The battery disconnecting device may be in the battery room (if space permits) or located just outside the battery room. The battery disconnecting device may be a disconnect switch or enclosed breaker. Disconnect switches must be non-fused type.

e. A fountain eyewash-safety shower and drain must be provided in the battery room or area near the battery.

(1) The water must be potable and tepid. Mechanical design should be provided as necessary for these fixtures to be properly plumbed, and to determine if the water supply must be heated to meet temperature requirements. See Chapter 26 for additional plumbing system considerations.

(2) The eyewash-shower system must have dry contacts to alarm in the event it is activated.

(3) If acid-absorbent material is provided within the battery rack spill barrier, the drain need not have special provisions unless it empties directly into the river. Typically, water from the eyewash/shower should sufficiently dilute any acid washed off from an affected person to prevent concerns. Mechanical design should be provided to determine requirements.

f. Hydrogen sensors and smoke detectors are required in the battery room or above the battery area. Sensors must alarm at 2 percent concentration of hydrogen. A pre-alarm is recommended at 1 percent concentration. Ventilation and air changes must be designed to keep hydrogen concentration below 2 percent.

g. The ventilation system must be alarmed to indicate failure. Exhaust air must be routed outside the powerhouse.

h. The door to the battery room must have a 3-hour fire rating. Where a fenced-in dedicated battery area must be used in lieu of an enclosed room, the surrounding area should have a 3-hour fire rating.

i. Periodic battery capacity testing is typically performed by disconnecting the battery from the DC system and connecting it to a load bank. To help accommodate this, a manual transfer switch is recommended between the battery disconnect and the DC bus breaker.

j. A battery lifting device should be provided, able to reach all batteries and maneuver them such that they can be loaded onto a cart for removal from the room with a direct, unobstructed path to the exit. For larger batteries, this may be a wall-mounted jib crane or a ceiling-mounted crane rail system. Mechanical and Structural designers should be involved with this aspect of battery room design. See Chapter 20 for additional guidance on lifting devices and systems.

k. The battery room layout and its detection and alarm systems should be reviewed by an Architect or a Fire Protection Engineer to verify compliance with NFPA 101, as well as other applicable NFPA and UFC standards.

12–5. Direct Current System Voltages

Most all USACE powerhouses have a DC system operating at a nominal 125 volts, with a targeted operating range of 100 volts minimum to 140 volts maximum. These systems are powered by station batteries of 58 or 60 cells, where cell voltage ranges between 1.9 volts and 2.2 volts per cell depending on the state of charge. Normal float voltage is typically 2.23 volts per cell after being fully charged. Equalizing is a slight overcharge performed periodically to raise cell voltage 2.4 to 2.5 volts per cell to help remove sulphate buildup on some cell plates and thus restore voltage balance across the cells. A resulting system voltage of well over 140 volts could damage relay coils, which is why most station batteries use 58 cells instead of 60 cells.

a. Some powerhouses used to have two separate station batteries: one for main unit starting (field flashing and auxiliaries), and one for controls where the flat waveform must have minimal disturbances during unit starting. In recent years, DC system power quality and the robustness of relays and control coils have improved to where this practice is no longer necessary.

b. Many larger powerhouses having over 8 main unit generators may have a 250-volt DC system for field flashing, high-load unit auxiliaries, and more extensive emergency lighting in addition to a 125VDC system for controls. Where 250 volts DC is required, two separate battery banks (125VDC and 250VDC) are suitable. The 250-volt battery bank uses 116 cells. Center-tapping a 250VDC bank to derive a 125VDC bank is not recommended because the charging and discharging will not be uniform across all cells. This leads to accelerated aging and plate degradation.

c. Most powerhouses used to have a dedicated 48-volt DC battery bank and system for SCADA. These have been replaced either by SCADA upgrades to 125VDC (requiring a larger 125-volt station battery and chargers), or by SCADA upgrades to 24 VDC systems. In such cases, a separate 24VDC battery bank, chargers, and DC system is suitable. Modern new SCADA systems may be 120VAC, but require extra capacity in the preferred AC system for reliable SCADA system power.

12–6. Direct Current Loads and Categories for Battery Sizing

Battery capacity is expressed in terms of amp-hours (Ah). The capacity needed for a station battery is determined by the need to provide the necessary amps demanded by the emergency loads for a pre-determined time until cell voltage drops to either 1.81 volts per cell or to 1.75 volts per cell at 77 °F (25 °C), depending on the criteria selected. USACE powerhouse practice is to size for 1.81 volts per cell. Manufacturers typically provide data for both ending cell voltages based on 8 hours of run time (or sometimes 10 hours for Planté cells) per industry standards.

a. There is no criteria for how long a powerhouse station battery must provide its rated power in the event all normal sources of station power is lost, but 8 hours is the accepted worst-case norm for calculating the required capacity. This time period is called the duty cycle. It can be reduced to fewer than 8 hours depending on the availability of other emergency station service sources such as diesel engine-generators with automatic starting. Batteries with less than an 8-hour duty cycle are not recommended unless all of the following considerations are discussed and considered.

(1) Where the 8-hour duty cycle causes the battery to be bigger to the point where it is unable to fit in the existing battery room and there are no other alternate locations to place the battery.

(2) There are multiple battery banks that can support the same DC loads.

(3) The criticality of the plant does not require an 8-hour duty cycle.

(4) The availability of a diesel engine-generator to provide backup AC power for the battery chargers. In such cases, the diesel engine-generator must be exercised regularly under near full load to help assure reliable starting in an emergency. Automatic start and transfer is recommended.

b. The summation of battery loads should be limited to those necessary for life safety, power needed to restore a normal source of station power, and power needed to keep the operating area from flooding in the meantime. This may include operation of a spillway gate to prevent overtopping the dam.

c. Battery sizing procedures outlined in IEEE 485 categorizes the various loads as follows, with some adjustments made for USACE hydroelectric powerhouses.

(1) *Continuous Loads*. Continuous loads consist of indicating lamps, inverters, contactor coils, emergency lighting, and other continuously energized devices. Continuous loads are assumed to be applied throughout the duty cycle. For large plants having 8 or more main units, the emergency lighting load may have a significant impact on the size of the battery. In such cases, the designer may elect to provide load shedding to disconnect half or more of the emergency lighting load after the first 3 hours.

(a) If load shedding is used for emergency lighting, only half (or more) of the total emergency lighting load is continuous throughout the duty cycle and remains on. The other half (or less) of the total emergency lighting load is then captured as a non-continuous load at the start of the cycle to be shed after 3 hours.

(b) If load shedding is used for portions of the emergency lighting, the load shedding process should be timed for automatic disconnection, unless an operating procedure for plant personnel is in place to perform manual load shedding.

(c) Areas where emergency lighting loads are shed should be areas in the powerhouse where no personnel are expected to remain behind during evacuation.

Only areas where personnel may be working to restore station power should be considered for continuous emergency lighting throughout the duty cycle.

(2) *Non-Continuous Loads*. Non-continuous loads consist of emergency pump motors, fire protection systems, and similar systems. Non-continuous loads are those energized for only a portion of the duty cycle or may cycle on and off during the duty cycle. This may include any portion of emergency lighting that is shed after 3 hours.

(3) *Momentary Loads*. Momentary loads consist of switchgear operations, generator exciter field flashing, voltage regulators, and similar devices. Motor inrush should be included for large DC motors for unit auxiliaries.

(a) Momentary loads are typically applied for one minute or less but are presumed to be for one minute for calculations. Momentary loads should be broken out as when they are expected to occur but should be grouped as a lump sum for one minute where there is no control over a sequence of operation.

(b) The grouped one-minute loads are typically accounted for at the very beginning of the duty cycle since breaker operations are to be expected within the first minute of a loss of normal power.

(c) Exciter field flashing, if delivered under batter power to restore station service, should be reserved for the very last one minute of the duty cycle. This is when the cell voltage is at its lowest, to provide the worst-case scenario for sizing the battery.

(4) *Random Loads*. Loads that occur at random should be shown at the most critical time of the duty cycle to simulate the worst-case load on the battery. These may be non-continuous or momentary loads as described above. To determine the most critical time, it is necessary to size the battery without the random load(s) and to identify the section of the duty cycle that controls battery size. Then the random load(s) should be superimposed on the end of that controlling section. Establishing the load profile as described below is helpful in making this determination.

12–7. Duty Cycle, Load Profile, and Battery Sizing

a. The duty cycle for the required station battery is presented in bar-graph format with amps along the vertical axis and time along the horizontal axis. The various bars represent the time intervals during which the various load categories are drawing power, represented as total load in amperes at that time. This is also referred to as a load profile.

b. Figure 12–2 shows a simple example of a load profile in which the first 1-minute momentary load is 74 amps, the first 10-minute non-continuous load is 53 amps, and the continuous load throughout the cycle is 108 amps. Thus, this battery must deliver a total 235 amps for the first minute, 161 amps for the next 9 minutes, and 108 amps for the remaining 7 hours and 50 minutes before dropping to 1.81 volts per cell.

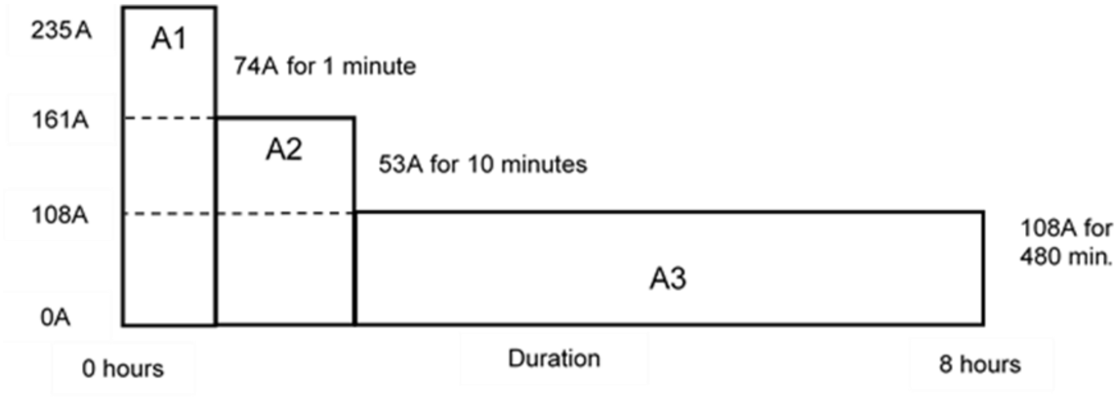


Figure 12–2. Example load profile for station battery sizing

c. IEEE 485 Annex A provides a method of calculating the optimum battery size based on the loads, timing, and durations depicted in the load profile. This is an iterative process made simpler with load worksheets used for the example calculation in Annex A of IEEE 485. A blank worksheet is provided in Annex I. Some battery manufacturers offer online software for calculating required battery size, but still requires the front-end work of developing the load profile for input into the software. Other factors not represented in the load profile but required for more accurate calculation include:

(1) *Temperature Correction Factor*. Battery manufacturers' data and IEEE calculation methods are based on an ambient temperature of 77 °F (25 °C). If it is known that the ambient temperature will differ, the temperature correction factor must be determined.

(2) *Design Margin*. Battery manufacturers' data and IEEE calculation methods are based on the assumption of a perfectly maintained battery with no growth allowance. A design margin of 10 percent to 15 percent additional capacity is recommended to account for load growth and a possibility of insufficient maintenance.

(3) *Aging Factor*. IEEE recommends that batteries be replaced when they degrade to 80 percent of their initial capacity. Thus, an aging factor of 125 percent is recommended to account for aging. This helps assure full design capacity remaining at the end of the battery's lifetime. However, some Planté cells do not degrade as much, and some manufacturers recommend an aging factor of 100 percent. See Annex H in IEEE 485 for further discussion.

12–8. Battery Charging Equipment

a. Lead-acid battery chargers typically use the constant current/constant voltage charge method. A regulated current raises the terminal voltage until the upper charge voltage limit is reached, at which point the current drops due to saturation. See IEEE 485 for further discussion of constant current charging and constant voltage charging.

(1) Battery chargers should be redundant and run in parallel. Each charger should have adequate capacity for carrying the continuous DC load while recharging the battery within a 12-hour period.

(2) Battery chargers should have load-sharing capabilities and filtering that meets or exceeds the battery eliminator requirements of NEMA PE 5.

(3) The 480V power feeds to the charger should be from two different and independent sources (such as two station service transformers). For a power plant with only one station service transformer, the 480V power feeds should be from two different switchboards.

b. Applying a periodic equalizing charge brings all cells to similar levels by increasing the voltage to 2.50V/cell, or 10 percent higher than the recommended charge voltage. An equalizing charge is nothing more than a deliberate overcharge to remove sulfate crystals that build up on the plates over time. Left unchecked, sulfation can reduce the overall capacity of the battery and render the battery unserviceable in extreme cases. An equalizing charge also reverses acid stratification, a condition where acid concentration is greater at the bottom of the battery than at the top. The equalizing voltage should be adjusted to prevent damaging field devices such as relay coils.

c. Static charger sets are preferred for battery-charging service. Two sets should be provided so one will always be available. The charger capacity should be sufficient for supplying the continuous DC load normally carried while recharging the station battery at a normal rate.

(1) The chargers should be of the “battery eliminator” type (additional filtering) allowing them to carry station DC loads while the battery is disconnected for service.

(2) The battery-charger systems should be located near the battery room, usually in a special room with the battery switchboard and the inverter sets.

(3) Standard commercial features and options available with station battery chargers are outlined in NEMA PE 5.

12–9. Battery Monitoring System

Each battery bank should have a battery monitoring system installed to monitor individual cell’s parameters, the battery as a whole, and to immediately alert an operator in the event of a problem.

a. At a minimum, the battery monitoring system should monitor the following parameters:

(1) Float voltage (battery array, or string).
(2) Cell voltage (individual cells).
(3) Cell/battery DC current.
(4) Cell/unit temperatures.
(5) Cell/unit impedance.
(6) Ambient temperature.

b. Although IEEE 1491 Part 6 lists several additional parameters for measurement, they are less important to battery health, and few, if any, monitoring system manufacturers support them all. Refer to IEEE 1491 in specifications for system performance and manufacturing quality and standards, but do not simply defer to Part 6 in lieu of listing the required measurement parameters.

c. The battery rack layout and location must consider the cell-to-cell wiring required for measuring performance. A wireway is recommended to route this wiring to data-gathering modules at the ends of the racks, but it must not interfere with accessing the battery cells for hands-on maintenance.

d. The computer or controller for the battery monitoring system should be located outside of the battery room.

12–10. Direct Current Switchboards

The battery breaker, DC feeder breakers, ammeters, and relays for ground detection and undervoltage should be grouped and mounted in the main DC distribution board (or SB board).

a. Multiple main distribution boards are recommended for redundancy in plants having more than 3 main units.

b. Each main distribution board should be redundant and have separately fed power sources (individual battery chargers) except for the battery.

c. Each main distribution board should be provided with ammeters, a voltmeter, and relays for ground detection and undervoltage. Where multiple ground detection relays are used in redundant battery switchboards on the same DC system, the relays should have an enable switch to allow turning one off or be connected in a master/slave setup to prevent interfering with each other and causing false alarms. In smaller plants with only one DC panel serving as the distribution board (CE panel), this instrumentation is required adjacent to or integral to the panel, and two feeder breakers should serve as redundant source breakers instead of paralleling both sources to a single main breaker.

d. Critical load panels, such as unit load panels (CE boards), should be fed by redundant sources from the main distribution boards. Loads such as emergency lighting and code call do not require redundant feeds.

e. The main 480V distribution switchgear that serve the battery chargers and the inverter bypass are recommended to have their own load panel with double-main breakers. The panel should be located near the switchgear.

f. Where the required trip rating or interrupting rating of a standard 2-pole DC breaker is not sufficient, a 3-pole breaker with the required ratings may be used. In such cases, two of the poles should be wired in series per the breaker manufacturer’s instructions such that all three poles operate automatically but provide 2-wire service.

12–11. Preferred Alternating Current System Inverter Equipment

Each inverter should have adequate capacity for carrying the entire preferred AC load. If it is necessary to start a main unit to restore station service power in an emergency and the unit has large AC auxiliary loads required for starting, a separate inverter is recommended for those main unit auxiliaries. Normal operation of main unit auxiliaries should not take up station battery capacity for an oversized preferred AC inverter.

a. Each inverter must have two independent power sources: the station DC bus for inverter DC input and a normal power bypass for the inverter AC input.

b. Each inverter should have its own 480/120VAC single-phase transformer for bypass power. The 480V power feeds to the transformers should be from two different sources (such as two station service transformers). For a power plant with only one station service transformer, only one inverter and one transformer are recommended.

c. Standard commercial features and options available with inverters used in uninterruptible power supplies are outlined in NEMA PE 1.

12–12. Alternating Current System Voltage

Preferred AC systems may be grounded or ungrounded; however, ungrounded is highly preferred because of greater reliability and the ability to continue operating with a ground fault.

a. Ungrounded systems require 2-pole breakers throughout the preferred AC system. Ground detection and alarm must be provided at the preferred AC panelboard.

b. Resistive neutral grounding is not used for 120-volt AC, as it is for normal three-phase station service power. If a grounded neutral for the preferred AC system is required, a 120-volt isolation transformer may be provided at the ungrounded inverter output to provide a separately derived system with a neutral grounding point. However, many inverters are now available with grounded output. Systems with inverters that have a grounded output may use single-pole breakers for preferred AC distribution.

12–13. Preferred Alternating Current Panelboards

Typically, redundant inverters power a single central preferred AC 2-pole 2-wire panelboard (or panel CH). Where redundant sources power the same panelboard, the two inputs to the panel should be interlocked at the breakers to prevent paralleling of two separately derived AC sources as shown in Figure 12–1. This results in a momentary interruption of preferred AC when switching between sources.

a. Where momentary interruption of preferred AC power cannot be tolerated, the two inputs may power an automatic transfer switch (ATS) that connects to the panelboard. In such cases, the ATS must be equipped for passive closed transfer with synch check.

b. Ground detection and alarm should be provided at the central preferred AC panelboard. Reliance on alarms at the inverter(s) alone is not recommended.

Chapter 13
Plant Distribution Systems (120V to 15 kV)

13–1. Station and Plant Distribution in General

Chapter 15 describes the basics of providing reliable power and backup power for mainly the critical powerhouse systems to maintain generation and in keeping the powerhouse minimally functional and survivable in the event of an emergency where the normal sources of power for these systems are unexpectedly lost. Beyond that scope, station service typically extends beyond the powerhouse at various voltage levels to all facilities within the boundary of the operating project, some of which may also be considered critical and thus needing backup power. This chapter focuses on low-voltage and medium-voltage distribution beyond the scope of Chapter 15 to cover the balance of the powerhouse and operating project. The following discussion of requirements are common for any system voltage.

a. *Scope*. The station distribution system ultimately extends to non-critical (also known as non-essential) loads throughout the powerhouse and to external loads outside the powerhouse, which may or may not require power source redundancy. The distribution system should be set up to allow shedding of all non-essential external loads as much as possible if the powerhouse loses all sources of normal power and must fall back on the source of emergency power.

(1) Spillway gates, regulating outlets, and intake structures should be connected to the station service medium-voltage or low-voltage systems from the powerhouse; however, these facilities may already have, or should be designed with, their own separate emergency power supplies with load-shedding of non-critical loads. If the total load is insignificant with respect to powerhouse backup capacity, load shedding and a separate backup system may be unnecessary, but should still be figured into the powerhouse emergency power scheme.

(2) Installations having navigation locks may consider the lock valves and gate operators to be critical loads. Navigation locks are usually an external station service load but are not normally required to have backup power as do spillways. If the navigation lock valves and gate operators are considered critical loads and do not have a separate backup power source (such as a dedicated standby diesel engine-generator), these loads should also be figured into the powerhouse emergency power scheme.

(3) Non-critical loads within the powerhouse include, but are not limited to, normal lighting and receptacles, offices, break rooms, maintenance rooms, locker and restroom facilities, HVAC, and non-critical pumps.

(4) Non-critical loads that are often powered by station service outside the powerhouse include project offices, warehouse, maintenance buildings, and visitor facilities.

(5) In some cases, powerhouse station service has been, or may be, extended to power fish facilities such as hatcheries and fish collection and bypass facilities on or adjacent to the operating project. This is acceptable if normal power to these facilities is provided by online main unit generation or is being backfed from the utility connection; however, fish facility pumping demand could be measured in the hundreds of horsepower. If improvements to the station service system, and especially to the station

service emergency power system, are driven by the needs of fish facility pumping (which could be measured in the hundreds of horsepower), alternate considerations for backup power to these facilities should be investigated. Most station service rehabs and upgrades are funded directly by the PMA receiving power from the powerhouse and will refuse to fund improvements not related to power generation.

b. *Durability*. Electrical systems and electrical equipment for residential and commercial facilities are typically designed for a 20-year life. This may be suitable for non-critical loads powered by station service outside of the powerhouse; however, all design for permanent construction within the powerhouse should provide a design life of at least 35 years, preferably 50 years.

c. *Available Space*.

(1) It is common for new switchgear to arrive on site only to find that it may be just a couple of inches too large to fit into the space shown on the contract drawings. Always verify that representative equipment will fit where intended, as well as verifying the dimensions of the intended locations. This must include required clearance and work space around the equipment, and take into account the location of floor/ceiling hatches, existing utilities such as water lines, and structural expansion/contraction joints. In no case should the frame of any equipment span a structural joint.

(2) If the feasibility of fitting the equipment depends on which manufacturer's version will fit, specify that the contractor is responsible for submitting dimensioned shop drawings showing that the equipment will fit; however, if only one manufacturer can satisfy this requirement, even considering custom designed enclosure dimensions, a new approach should be considered to avoid creating a de-facto sole-source situation. Another alternative is to prepare justification and authorization for sole-source procurement of this one manufacturer's equipment based on space constraints.

d. *Maintainability*. The design of electrical systems must incorporate features that provide access space for maintenance consistent with NFPA 70 and IEEE C2 Consider having a means to replace equipment and field-installed wiring without significant demolition and reconstruction of parts of the facility.

e. *Capacity*. Guidance for estimating electrical demand loads for hydroelectric powerhouses is provided in Chapter 15. For non-hydropower loads connected to station service, refer to the NEC Article 220.

f. *Short-Circuit and Coordination Studies*. Short-circuit and protective devices coordination studies should be performed for new installations as well as expansion or rehab of existing systems consistent with IEEE 242 and documented according to ER 1110-2-1150.

g. *Remote Control Panels*. To eliminate arc flash hazards when manually operating breakers, remote control panels are typically provided near the switchgear to open or close the electrically operated mains and tie breakers, and any feeder breakers as desired.

h. *Switchgear*. Switchgear must have either low-voltage power circuit breakers and conform to IEEE C37.20.1 or medium-voltage circuit interrupters conforming to IEEE C37.20.2 (breakers only) or IEEE C37.20.3 (breakers or fuses and disconnects). All such switchgear should have breakers or other interrupters that can be serviced or repaired in the field without complete replacement of the device. Switchgear typically has rear access to the buses.

i. *Fixed Breakers Versus Drawout Breakers*. Air-insulated power circuit breakers are either drawout, meaning they rack out of their cells, or fixed, which means they bolt into their cells. Drawout breakers can be racked out with a racking tool with the bus still energized. A fixed breaker must be unbolted from the rear bus that connects to the back of the breaker, requiring a bus outage. Although drawout breakers are more expensive, they are highly preferred to increase the in-service availability of other loads connected to the same bus.

j. *Power Circuit Breakers*. Whether fixed or drawout type, and whether manually or electrically operated, power circuit breakers have a spring to force rapid operation of the contacts under load.

(1) Manually operated breakers are equipped with a manual charging handle to charge the springs. These breakers cannot be remotely operated without addition of devices to operate the spring release mechanism by shunt-tripping the breaker to the open position, after which the spring must be manually charged. Remote closing is not possible. For critical feeders, this is recommended only at plants that are staffed around the clock where manual intervention is immediately available if required.

(2) Electrically operated breakers are equipped with a spring charging motor, electrically operated spring release, and shunt trip coils, typically powered by the powerhouse 125 VDC system. A manual charging handle may be used to charge the springs when power is not available to the charging motor. These breakers may be remotely opened and closed indefinitely as long as control power is available. Close/trip pushbuttons are provided for manual operation of the electrical mechanisms. All station service mains and tie breakers, and critical feeder breakers should be electrically operated to allow automatic transfer, even if the plant is staffed around the clock.

k. *Metering and Instrumentation*. Metering is common for both medium-voltage and low-voltage switchgear. CTs are typically bushing type but can be bar type if required to meet certain performance requirements. VTs may be drawout type for medium-voltage switchgear, but are usually fixed inside the switchgear enclosure for low-voltage switchgear. The instrumentation and VTs typically take up the space of one breaker cubicle. For additional guidance on instrument transformers, see Chapter 9.

l. *Arc-Resistant Switchgear*. Arc resistant switchgear is designed to contain and vent an arc blast away from the enclosure, and has become recently popular; however, arc-resistant switchgear typically requires a significant additional amount of vertical space for venting the blast to outside the powerhouse. Venting the blast within the powerhouse is not advised. When replacing switchgear in an existing powerhouse, do not presume that arc-resistant switchgear will fit within the available space vacated by existing switchgear without first researching if it is physically possible. Arc hazard reduction by incorporating remote racking and better selective relaying is recommended. Arc hazard reduction can also be provided in switchgear by incorporating arc reduction maintenance switches, remote racking, and optimum selective relaying.

m. *Switchboards*. Switchboards have factory-sealed, molded-case circuit breakers, insulated case circuit breakers, or fusible switches and conform to Underwriters Laboratories (UL) 891. These breakers (or switches) have no provisions for service or repair in the field other than replacement of the entire device within the switchboard. Switchboards may or may not have rear access. Panelboards are basically switchboards limited to 600 volts for overcurrent devices not used for switching and have no rear access. These distinctions are described in more detail in the following paragraphs.

n. *Automatic Transfer*. Chapter 15 describes automatic transfer schemes where a large distribution center for critical loads may have two separate source buses connected by a tie breaker to automatically switch from one source to the other if power is lost on one of the sources. Although this is not necessary for non-critical loads, the size of the distribution center and the degree of inconvenience of an extended outage could warrant two source buses and a tie breaker; however, automatic transfer is necessarily required for a center serving only non-critical loads.

o. *Voltage Ratings*. ANSI, IEEE, and other industry standards do not completely agree on exactly where low-voltage becomes medium-voltage. In practice, any system operating at under 1,000 volts is considered to be low voltage, any system operating at over 1,000 volts up to 69 kV is considered to be medium voltage. For USACE powerhouses, the medium-voltage equipment ratings range from 2.4 kV to 15 kV.

13–2. Medium-Voltage Distribution (2.4 kV to 15 kV)

a. The recommended voltage for the medium-voltage part of station service distribution is 13.8 kV or 4,160 volts. The generation voltage determines the station service medium-voltage distribution level. Main unit generators commonly have a high-resistance-grounded or reactance-grounded neutral. High-resistance-grounding has been replacing reactance-grounding in most powerhouse upgrades and is now more prevalent. When the generator is running, the system operates as a high-resistance-grounded or reactance grounded system. When the generator is not running and the unit breaker is open, the system is backfed from the grid through the generator step-up transformer and operates as an ungrounded delta system because the low voltage winding of the transformer is connected in a delta configuration.

b. Many large plants were built with 2,400-volt station service distribution because of the presence of dedicated station service hydropower generators generating at 2,400 volts. This voltage is becoming less common, as NEC requirements have evolved to require shielding of cables at this voltage and thus eliminating the advantage of using non-shielded cables. In some recent station service rehabilitation projects, step-up transformers have been provided on 2,400-volt generators to provide 4,160-volt distribution to allow standardization on 5 kV switchgear having more room for shielded cable terminations.

c. *Breaker Classes*. Medium-voltage circuit breakers used to be differentiated as either station class or distribution class. IEEE C37.04 and IEEE C37.06 now define medium-voltage breakers as either Class S1 (formerly distribution class) or Class S2 (formerly station class). This chapter focuses on Class S1 (distribution) breakers. See Chapter 10 for further discussion and comparison of these breaker classes.

d. *Metal-Clad Switchgear Versus Metal-Enclosed Switchgear*. The ME abbreviation typically denotes ME switchgear that just contains circuit breakers; if fused disconnects or other interrupters are used, it is more commonly referred to as MEI (for metal-enclosed interrupter switchgear). Class S1 breakers may be drawout-type used in switchgear under IEEE C37.20.2 or either fixed type or drawout type used in switchgear under IEEE C37.20.3. MC switchgear is built to more stringent requirements and more robust performance and is recommended for the primary point of station service distribution. ME switchgear tends to be much less expensive.

(1) The preferred voltage ratings of non-generator breakers for either type of switchgear in USACE powerhouses are 5 kV/60 kV BIL for systems up to 4,800 volts, and 15 kV/95 kV BIL for systems up to 14,400 volts under the applicable IEEE standards.

(2) The preferred continuous current ratings of the main bus in MC switchgear are 1,200 amps, 2,000 amps, 3,000 amps, and 4,000 amps under IEEE C37.20.2. Rated interrupting current is determined by IEEE C37.04 based on breaker response time, but most manufacturers offer up to 63 kA rms symmetrical.

(3) The preferred continuous current ratings of the main bus in ME switchgear are 600 amps, 1,200 amps, and 2,000 amps under IEEE C37.20.3. Rated interrupting current can be as high as 50 kA rms symmetrical, but most manufacturers offer up to 63 kA rms symmetrical.

e. Interrupter Types.

(1) Vacuum interrupters are the most common at all medium-voltage levels, and are recommended for powerhouse distribution.

(2) SF_6 interrupters are available for 15 kV switchgear but are mostly designed under IEC standards at non-IEEE voltage ratings. There are limited domestic sources. Although SF_6 is better suited for very high fault currents, SF_6 circuit breakers require special care and handling. The gas is not environmentally friendly, and can be hazardous to health in high concentrations.

(3) Magnetic and air-blast interrupters are obsolete and no longer available on the market. These types of breakers should be replaced with modern vacuum breakers.

(4) Medium-voltage ME interrupter switchgear may use load-break fused disconnect switches instead of breakers. This is not typical practice for generators or main distribution switchgear, but load-break fused disconnects are sometimes used as a protection and disconnecting means for single-ended non-critical loads.

13–3. Low-Voltage Distribution (120V–480V)

a. 480 Voltage. The recommended voltage for the low-voltage part of station service distribution is 480 volts 3-phase. This is derived from a delta-connected transformer or from a high-resistance-grounded, wye-connected transformer to provide service continuity in the event of a ground fault.

(1) Using 480 volts for the major portion of low-voltage powerhouse distribution provides less voltage drop, especially when starting large motors for station systems or main unit auxiliaries. This advantage offsets the cost of providing step-down transformers for more common 120-volt loads such as lighting and receptacles, even for small single-unit plants.

(2) If a wye-connected station service transformer is used, the neutral is to be high-resistance grounded as described in Chapter 15 for reliability. Providing a 277-volt system for lighting, as is common in large commercial facilities, requires a solidly grounded neutral that is not available to the distribution system when the source neutral is high-resistance grounded.

b. 120/208 Voltage. The recommended voltage for the general lighting, receptacle, and other utilization loads not covered by critical backup systems such as emergency lighting and controls as described in Chapter 12 is 120/208 volts 3-phase. There are typically several station service and main unit auxiliaries requiring 3-phase power but small enough for 208 volts.

(1) 120-volt 1-phase loads should be powered from 120/208-volt, 3-wire, 4-pole panelboards as much as possible to allow balancing of the loads across all three phases.

(2) 120/208-volt step-down transformers powering these panelboards should be solidly grounded.

c. Distribution Equipment.

(1) The preferred equipment for 480-volt station service distribution is ME switchgear meeting the requirements of IEEE C37.20.1. This type of switchgear uses power circuit breakers that are covered under IEEE C37.13. Power circuit breakers rely on current sensors and trip units, making them versatile for various settings of trip current and trip response times.

(2) Although ME switchgear can have main bus ratings as high as 10,000 amps, the largest power circuit breakers available are 5,000 amps per IEEE C37.13, although some manufacturers offer up to 6,000 amps. More common hydropower installations have up to 2,000 amp mains and tie breakers, and up to 800 amp feeder breakers.

(3) Rear access is usually required for termination of incoming and outgoing feeders to the main bus. For lineups where substation step-down transformers are installed at one or both ends of the lineup, the transformer low-voltage connection to the switchgear bus may be “close-coupled,” in which the bus is directly connected to the transformer, or cable-connected, in which case a transition compartment is usually required to terminate cables between the transformer and the switchgear bus.

d. Switchboards. Switchboards are freestanding enclosures normally composed of fixed-mounted, molded case circuit breakers (MCCBs). Although power circuit breakers may be installed in switchboards, hydropower practice is to use power circuit breakers only in switchgear. Incoming and outgoing cable terminations can be accessed from the front, so the assembly does not require rear access and can be mounted against a wall; however, the entire board must be de-energized to service any of the breakers. The MCCBs may be shunt-tripped by a control signal if required, but that is essentially the only alternative of remote automatic operation.

(1) MCCBs have only a 3-cycle short-time current withstand rating, selective coordination is thus more difficult in smaller frame sizes since short-time delays cannot be programmed to provide time for circuit breakers farther downstream to clear faults, as can be done on power circuit breakers having longer current withstand ratings. Some larger frame MCCBs offer adjustable settings and interchangeable trip units. Frame sizes offering these features vary between manufacturers.

(2) Metering and instrumentation are typically available for switchboards, but requires CTs and VTs the same as for switchgear. Window CTs are used around bus or cables, as bushing CTs are not applicable to MCCBs.

(3) Switchboards are suitable for distribution to powerhouse systems and some main unit auxiliaries, but do not contain motor starters and controls like a motor control center. Switchboards are not suitable for generators or the source of distribution for station service due to the typically higher interrupting currents required that are better suited for power circuit breakers. Switchboards may also use fused switches instead of

breakers, but this is not typical practice in hydropower. Breakers can be reset, but fuses must be replaced and therefore a stock of the proper fuses must be kept in inventory.

e. Motor Control Centers. MCCs provide a convenient grouping of motor starters and controls within the power distribution equipment, which allows less clutter and hazards at the utilization equipment where space is often at a premium. NEMA 1 enclosures are suitable for clean and controlled environments. NEMA 12 is recommended for dirty and/or oily environments or where temperature is not well controlled. Such environments should require enclosure strip heaters to help reduce condensation.

(1) A typical current rating for the horizontal main bus is 800 amps but could be as much as 3,200 amps maximum. If main breakers are required, they typically go into sections at either end of the MCC lineup.

(2) A typical current rating for the vertical distribution buses is 600 amps but could be as much as 1,200 amps maximum or as little as 300 amps minimum.

(3) The various motor starters, controls, and protective devices are grouped in “buckets” connected to the vertical buses, one above another as space permits. MCCs typically require several vertical sections to accommodate the number of buckets required.

(4) The NEMA size of a motor starter determines the physical size of each bucket. Preliminary layouts should consider arranging the buckets to minimize the number of vertical sections required for the MCC.

(5) Many MCC manufacturers are designing more toward IEC motor starters, but still offer provisions for NEMA motor starters. IEC standards narrow down a starter to a specific physical size, which is usually much smaller than an equivalent NEMA starter. An IEC starter is limited to the specific driven load. NEMA starters have broad applications for any load and allow more flexible operational changes in the future. Ensure that the MCC and its specifications are designed around NEMA starters, and do not allow an equivalent IEC starter as an alternative.

(6) NEMA starters may be either full voltage, “across the line” type; starting motors with full-rated inrush current and voltage drop; or reduced-voltage type that starts motors with a lower voltage and inrush current, gradually increasing to full voltage as the motor comes up to speed. Reduced voltage starters allow more responsive system performance but typically require larger buckets than equivalent full voltage starters.

(7) Reduced voltage starters may be electromechanical type or solid-state type. Either type reduces the voltage at startup but does not control the running speed of the motor. VFDs are solid-state starters that can also vary motor speed while the motor is running.by varying the frequency. VFDs require significant programming of various settings after installation to insure proper performance. VFDs may also introduce harmonics to the connected distribution system, which should be considered early in the design process if VFDs will be used.

(8) Buckets near the main bus may be used for instrument transformers and metering as required.

f. Panelboards and Load Centers. Panelboards are wall-mounted enclosures, either flush with the wall or surface-mounted, containing MCCBs for branch circuits to end-use loads.

(1) 480-volt, 3-pole 3-wire panelboards are commonly used for general distribution of 480-volt 3-phase power to various powerhouse loads instead of freestanding switchboards. Since 277-volt loads are not typically used in powerhouses, 4-wire panelboards should not be specified for 480-volt distribution.

(2) 120/208-volt, 3-pole 4-wire panelboards are commonly used for 120-volt lighting and receptacle loads, and 208-volt, 3-phase for power to small motor loads such as powerhouse fans and pumps. The neutral bus should be solidly grounded. Bolt-on breakers should be required, disallowing the use of plug-in breakers. Bolt-on breakers tolerate constant vibration and higher fault currents much better than residential-grade plug-in breakers; however, if the panelboard is an integral part of an MCC vertical section, plug-in breakers may be the only choice, which can be accepted in such cases.

(3) Panelboards for DC distribution should be 2-pole, 3-wire type, whether or not the DC system is grounded. The ground lug could be used for equipment safety grounds.

(a) Few panelboards are rated solely for DC distribution; most are dual rated for 240VAC or 250VDC. Verify that the specifications for panelboards and breakers call out a 250VDC rating rather than just relying on a dual rating.

(b) All DC breakers should be 2-pole. If a powerhouse has both a 250VDC system and a 125VDC system, separate DC panels are recommended to separate the voltages and avoid confusion, as well as allowing the 250 DC system to not be center-tapped for 125VDC. Using a center-tapped 125/250VDC station battery is not recommended, as discussed in Chapter 12.

(c) In some cases, a breaker for large DC loads may have too high a trip rating or interrupting rating for a dual-rated 2-pole breaker. A suitable 240VAC 3-pole breaker may be used if it is wired in series such that one leg loops through two of the poles, as recommended by some breaker manufacturers, to effectively make it a 2-pole breaker. If this is permitted in the specifications, verify that a submittal is required to show the breaker manufacturer’s concurrence with this approach.

Chapter 14
High-Voltage Systems (over 15kV)

14–1. Definition

a. 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.

b. ANSI C84.1 defines nominal system voltages between 2.4 kV and 69 kV as medium voltage, and 115 kV and above as high or extra high voltage. The highest USACE generation voltage is 14.4 kV, so for purposes of this chapter, the high-voltage system is anything over 15 kV.

c. This system begins at the high-voltage terminals of the GSU power transformers and extends to the point where transmission lines are attached to the takeoff structure. The takeoff structure may be located either in a switchyard or at the powerhouse, on the roof, or along a powerhouse wall. The transmission lines leaving the takeoff structure are typically owned by the utility. Transmission line corridors from the takeoff structure should allow adequate clearance for maintenance equipment access, and clear working space.

14–2. Switchyard Basics

Switchyards and substations are two terms often used interchangeably. They basically refer to the same type of installation with the common use of “substation” where transformers are present, and “switchyard” where no transformers are present. This chapter refers to all such facilities as switchyards. See Chapter 4 for further guidance.

a. *Minimum Requirements*. The initial installation may require connecting only a single transformer bank to a single transmission line. In this case, one circuit breaker with a disconnect switch on either side is preferred. The transmission-side switch should have a ground switch to ground the transmission line. The high-voltage circuit breaker may even be omitted under some conditions. The receiving utility generally establishes the system criteria that dictates the need for a high-side breaker. Where a breaker is not used, a motor-operated disconnect switch is recommended, with a ground switch to ground the transmission line.

b. *Space Around the Switchyard*. Allow adequate space for extension of the switchyard facilities when generating units or transmission lines are added in the future.

c. *Switchyard Location*. Subject to these criteria, the switchyard should be sited as near to the powerhouse as space permits, to minimize the length of control circuits and power feeders, and also to enable using the service facilities located in the powerhouse.

d. *Switchyard Fencing*. IEEE 80 recommends that the switchyard grid extend beyond the fence line and provide some fence grounding requirements. IEEE C2 provides guidance on fence requirements and construction. A chain-link, woven-wire fence not less than 7 ft (2.1 m) high and topped with three strands of barbed wire slanting outward at a 45-degree angle, or concertina wire, with lockable gates, should be provided to enclose the entire yard.

14–3. Bus Structures

a. Arrangement. The low-profile type of bus construction with pedestal-supported rigid tubular buses and A-frame line towers is ordinarily the most economical where space and topography are favorable. Congested areas may require a high, narrow steel structure and short wire bus connections between disconnecting switches and the buses.

(1) Switchyard layouts should provide adequate access for safely moving maintenance equipment and future circuit breakers or other major items of equipment into position without de-energizing primary buses.

(2) Clearances to energized parts should, at a minimum, comply with IEEE C2, section 12.

(3) Equipment access requirements should be based on the removal of high-voltage bushings, arresters, conservators, and radiators from large power transformers.

b. Bus Design. 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.

(3) Spacing of bus supports should limit tubular bus sag under maximum loading to not greater than the diameter of the bus, or 1/150th of the span length.

(4) IEEE 605 provides further information on substation electrical, mechanical, and structural design considerations.

14–4. Switchyard Materials

a. General. Design drawings showing a general layout of the switchyard and details of electrical interconnections should accompany the specifications for procurement and construction. The drawings should show the size, spacing, and location of principal members and support the design loading assumptions (ice, wind, seismic, and short circuit forces) made for the switchyard.

b. Structure Materials. The direct contact of dissimilar metals could lead to galvanic-driven corrosion over time. Contact of certain metals with concrete may also lead to eventual corrosion. Consult a mechanical, structural, or corrosion engineer to mediate such concerns when they arise. The following are four types of material most commonly used for substation structures.

(1) *Steel*. Steel is the most 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 (such as 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 (an acidic environment, such as conditions existing in a brine mist), galvanized structures 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.

(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, but are not recommended for permanent structures. Wood members must be treated with an appropriate preservative.

c. *Switchyard Gravel*. The switchyard surface must be covered with a relatively non-conductive (at least 30,000 ohm-meters) gravel to insulate people working in the switchyard from the ground grid while still reducing step potential and touch potential. This practice also allows water to drain, as well as helping to control vegetation and the spread of fire. But ordinary gravel may not be suited for this purpose. IEEE 80 recommends between 3 in. to 6 in (7.6 to 15.2 cm). of gravel cover. Rural Utilities Service (RUS) Bulletin 1724E-300 recommends 4 in. to 6 in (10.2 to 15.2 cm). In no case should the gravel depth be less than 4 in (10.2 cm).

14–5. Switching Schemes

Switchyard switching schemes are covered in Chapter 4.

14–6. Switchyard Bus Types

There are two basic types of bus for high-voltage switchyards: strain bus and rigid bus.

a. Strain bus is bare-stranded conductor supported by strain insulators, usually hanging below a steel latticework or other structure. The insulators are relatively close together such that the bus is more or less draped along the underside of the horizontal structures with little sag. The sag allows thermal expansion and contraction, as well as flexibility in windy conditions where aerodynamics may cause vibration.

(1) Strain bus is most always a type of stranded aluminum due to its lower cost and weight compared with copper. The stranding may have a steel core for physical strength in long suspended runs, but is not required when supported by a lattice structure end to end.

(2) One disadvantage of using large gauge stranded conductor is that the strands may tend to unravel during the termination process, causing what is called “bird-caging” of the outer strands.

b. Rigid bus is almost always tubular aluminum segments supported above individual supporting pedestals and below A-frame steel structures. The tubular structure allows lighter weight and better resistance to bending, as well as taking advantage of the “skin effect” where power frequency current tends to travel mostly along the outer surface of a conductor.

(1) Tubular bus is usually specified by its IPS (iron pipe size), which identifies the pipe's inner diameter, and by its "schedule," which defines its wall thickness based on ASTM standards. Schedule 40 is most often used and may be referred to as "standard" or "thin wall." Schedule 80 is sometimes referred to as "heavy duty" or "thick wall," and is used only where additional strength is required to prevent deformations from long spans, high winds, or high short circuits. Small drain holes should be provided at low points to prevent water from accumulating. Water trapped inside a tube can fracture the side of the tube during freezing temperatures.

(2) The preferred aluminum alloy and temper is 6061-T6 as defined by ASTM B308, or 6063-T6 as defined in ASTM B221.

(3) Aerodynamics may cause rigid bus to vibrate or oscillate in high winds, eventually leading to cracks appearing in the tube wall. This is an effect that expansion fittings cannot prevent. When such conditions are expected, common practice is to run a "damping conductor" inside the tube that dissipates the vibration energy. IEEE 605 provides some guidance on this practice.

14–7. Insulators

There are two common types of insulators for supporting bus in a high-voltage switchyard: suspension insulators and post insulators. Both types are available with either ceramic or polymer construction. The selection of ceramic versus polymer is typically a preference expressed by the project or the PMA/utility. Ceramic insulators are more prone to shatter under force, while the expected life of polymer insulators is less than for ceramic insulators. Either type features a stack of "rain sheds" or "skirts" along the insulator tube making it impossible for falling rain or even high humidity to establish a short direct straight path of flashover between the conductor and the base of the insulator.

a. Suspension insulators are flexible assemblies of individual insulating discs connected like links in a chain. For this reason, they are often referred to as string insulators. Suspension insulators provide tensile strength in supporting strain bus from above or from one end, including dead-end takeoffs. They can conform to the catenary curve of the hanging conductor at the conductor termination, or remain straight when supporting a strain bus mid-span from above.

(1) The technical requirements of ceramic suspension insulators are covered by ANSI C29.2A and ANSI C29.2B.

(2) The technical requirements of composite suspension insulators are covered by ANSI C29.12 and ANSI C29.13.

(3) Suspension insulators are not to be confused with "strain" insulators covered by other ANSI standards. Strain insulators are more appropriate for medium-voltage application.

b. Post insulators are rigid assemblies of insulating discs providing compressive strength in supporting rigid bus from below or cantilever strength in supporting rigid bus or strain bus from the side or at changes in direction or elevation.

(1) Ceramic line post insulators are covered by ANSI C29.7.

(2) Composite line post insulators are covered by ANSI C29.17 and ANSI C29.18.

(3) Line post insulators are not to be confused with “pin” insulators covered by other ANSI standards. Pin insulators are more appropriate for medium-voltage application.

c. Apparatus post insulators are similar to line post insulators, except that they have been designed for disconnect switches and other electrical apparatus. These are discussed later for disconnect switches.

d. Insulators may be ceramic or glass, or a polymer material (sometimes referred to as a composite). Most composite insulators use epoxy/glass tubes with silicon rain sheds. Composites are becoming more popular as that technology matures. On the one hand, porcelain may shatter in dangerous fashion when physically abused, but not composites; on the other hand, porcelain is essentially immune to ultraviolet deterioration while composites may eventually become brittle and degrade under ultraviolet (UV) stress. Expansion of existing switchyards should use insulator materials matching existing.

e. Cap and pin insulators are assemblies of individual disk segments. These insulators may fall into any of the above categories but are rarely used today. They were prone to eventual failure while in service, having a shorter life expectancy than modern products. Although many manufacturers offer cap and pin replacements to match existing, preferred practice is to replace all cap and pin insulators with modern post-type insulators when given the opportunity to do. See Figure 14–1 for a visual comparison between a 115 kV cap and pin post insulator using three disks, and an equivalent modern 115 kV post insulator. A 230 kV cap and pin insulator uses six disks, while the modern 230 kV post insulator is just taller.

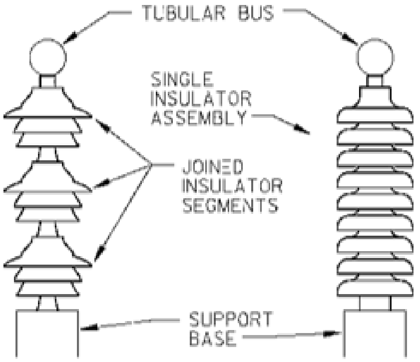


Figure 14–1. Cap and pin insulator (left) and modern insulator (right)

14–8. Powerhouse – Switchyard Power and Control Circuits

a. *Conductor Routing*.

(1) *Cable Tunnel*. Tunnels running just below switchyard grade from the powerhouse is the preferred method. Using a tunnel provides ready access to the cables, provides 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.

(a) The control cables (including relaying, metering, annunciation, and low-voltage power) should be carried in trays in the tunnel and continued in steel conduits from the trays to circuit breakers and other controlled equipment to eliminate the need for manholes and handholes. If there is a control house in the switchyard, it should be situated over the tunnel. The tunnel should be lighted and ventilated and provided with suitable drains, or sumps and pumps.

(b) If the generator leads, transformer leads, or station service feeders are located in the tunnel, the amount of heat dissipated should be calculated and considered in providing tunnel ventilation. The power cables should be carefully segregated from the control cables to prevent EMI 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.

(c) Cables for RTDs, those carrying analog signals, or operating at or below 24 volts should be shielded and physically separated from power and control circuits.

(d) Depending on the arrangement of equipment in the switchyard, size of the switchyard, cost limitations, and available real estate, separate tunnels for power and for control should be provided. If high- or medium-voltage power circuits and low-voltage (under 1,000 volts) circuits share the same tunnel, the power and control circuits must be physically separated. All high- or medium-voltage power circuits should be run along one wall of the tunnel, and control and low-voltage circuits should be run along the opposite wall.

(2) *Duct Bank*.

(a) For small installations having limited transforming and switching equipment, it may be desirable and economical to use a duct bank instead of a cable tunnel for control and power cables.

(b) The duct system should use concrete-encased, nonmetallic conduit. Manholes and handholes of adequate number and size should be provided. The manholes should be designed to drain unless costs are prohibitive.

(c) Separate ducts for the power cables and the control 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 cables.

(3) *Precast Concrete Trench Duct*. If geographic conditions permit, and a limited amount of cabling is required, precast concrete utility trench with removable covers may be considered. The covers must be nonflammable and capable of withstanding the uplift of high winds. Trench duct is cost-competitive with constructing a concrete duct bank and allows periodic checking on the condition of the cables. Drainage must be considered.

(4) *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 cable failures or leaks in pressurized cable systems, the accessibility of the cable system in a tunnel or trench duct will speed repairs and could avoid considerable loss of revenue.

b. High-Voltage Bus to Switchyard. If the GSU transformers are located at the powerhouse, the cables to the switchyard may be stranded bare aluminum aerial cable between takeoff structures, or insulated copper cables in a tunnel or duct bank.

(1) Aerial cable drops should be bare, stranded aluminum cable, steel-reinforced (ACSR). The steel core provides tensile strength for the aluminum conductor. ACSR sizes over number (No.) 4/0 American Wire Gauge (AWG) follows a different standard range of kcmil sizes. Size and stranding combinations are identified by avian or floral code words by the Aluminum Association and are used by all cable manufacturers to identify specific combinations. A steel static ground wire is required above the span for lightning protection.

(2) Solid dielectric cable is typically available up to 500 kcmil and 230 kV. The cables may be run in cable tray in a switchyard tunnel. Cleating for short-circuit restraint should be provided. Top and bottom covers are not required on the tray; however, some operating projects prefer this for high-voltage cable. In such cases, consult the cable manufacturer to verify any derating required for the cables being totally enclosed. Conduit is not recommended. Do not run cables in pipes that may have been vacated by pre-existing high-pressure oil or gas-insulated cables.

(3) HPFF and high-pressure gas-filled (HPGF) cable systems are available in a wide range of sizes and voltages, 69 kV and higher. These are paper-insulated cables in large pipes filled with pressurized insulating oil, or pressurized gas (nitrogen or SF_6), at roughly 200 psi (1379 kPa). A piping system infrastructure and storage tank are required to manage the insulating medium.

c. Medium-Voltage Bus to the Switchyard. If the GSU transformers are located in the switchyard, the powerhouse-switchyard circuits should be a type of medium-voltage cable.

(1) Aerial ACSR cables may be used if geographic conditions prohibit using a tunnel or duct bank. The higher ampacity requires large cable sizes and thus limits span length between supporting structures.

(2) Solid dielectric cable is typically available up to 1,000 kcmil and 15 kV. The cables may be run in cable tray in a switchyard tunnel. Cleating for short-circuit restraint should be provided. Top and bottom covers are not required on the tray. Conduit is not recommended. Do not run cables in pipes that may have been vacated by pre-existing high-pressure oil or gas-insulated cables.

(3) The maximum recommended size of conductor for cable tray is 1,250 kcmil. Although cables may be special ordered in larger sizes up to 3,000 kcmil, such cables have been known to cause damage to themselves and to cable tray under normal thermal expansion and contraction. For cables this large, a transmission style of hanging cables over saddle-type supports is recommended. See Chapter 33 for an example of a saddle-supported cable system.

(4) High-pressure cable systems under 69 kV are no longer covered by industry standards and are no longer offered by manufacturers. Where existing medium-voltage HPFF or HPGF systems must be replaced, an alternative method must be selected.

(5) Some powerhouses have a medium-voltage LPGF cable system in the switchyard tunnel. This system uses lead sheath-insulated, 3-conductor, paper-insulated oil-impregnated cable similar to paper-insulated, lead-sheath (PILC) cables, but with nitrogen pumped through porous tubes between the conductors at 15 psi (103 kPa). Such cables are run in conventional cable trays and require a nitrogen management infrastructure. Where existing LPGF replacement is necessary, a more conventional alternative is highly recommended.

(6) A relatively new type of solid bus known as “solid-insulated” or “resin-insulated” bus may be used in tunnels or trench duct for higher ampacities at medium voltages than cable. See Chapter 9 for a description of this bus type. Traditional segregated or nonsegregated-phase bus in the required ampacities typically proves economically infeasible or requires more space than available when replacing an existing pressurized cable system.

14–9. Disconnect Switches and Ground Switches

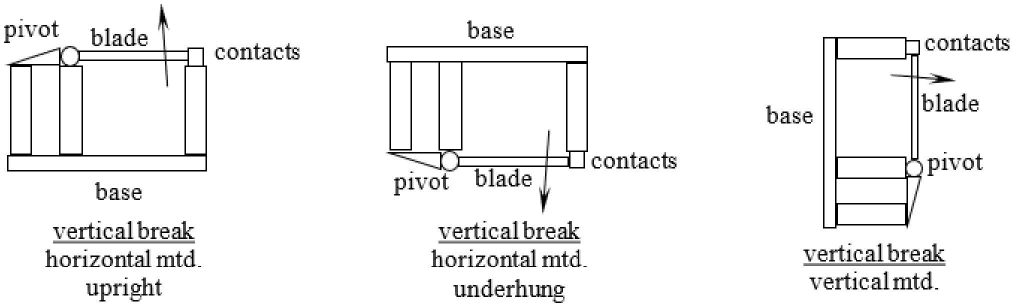
a. General. Disconnect switches (also known as GOAB switches, for “gang-operated air break”) are non-load break devices, to be opened and closed only when the load is removed (no-load condition) or the source de-energized.

(1) Even with the system unloaded, a switch may still see a relatively small current on opening or closing due to magnetizing current of unloaded transformers or charging current of unloaded transmission lines. Such currents are not considered load current, but they can result in arcing until the contacts have been moved far enough apart for the dielectric strength of the air to break the arc. Disconnect switches are designed for this, but opening an energized switch under partial or full load causes severe arcing and possible destruction of the switch.

(2) Disconnect switches are covered by IEEE C37.30.1.

b. Disconnect Switch Configurations. Disconnect switches have two or three insulator stacks per pole, separating the live switch blades from the grounded base of the switch. One of the insulator stacks rotates to move the switch blades through a mechanical linkage.

(1) *Vertical Break Switches*. Figure 14–2 shows vertical break disconnect switches, where the blades move perpendicular to the base of the switch. These are most typically used in USACE switchyards because of their operating simplicity and reliability. Also, because arcs in air always propagate upward, this is the safest configuration as the arc does not propagate toward a grounded structure, including parts of the switch itself.

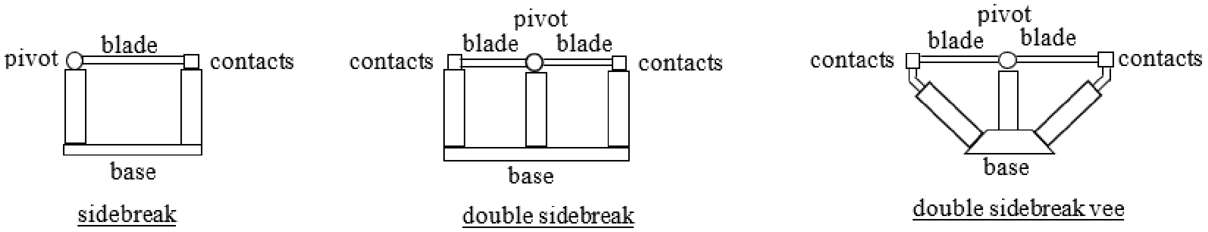


Arrows indicate blade travel parallel to the plane of the diagram

Figure 14–2. Vertical break switch configurations

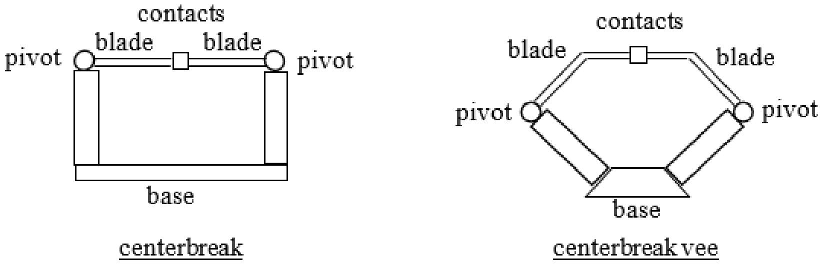
(2) *Sidebreak Switches*. Figure 14–3 shows sidebreak switches. In sidebreak configurations, the switch blades move parallel to the base of the switch. Double sidebreak vee switches are more compact but are rarely used unless space constraints prevent the use of the other configurations.

(3) *Centerbreak Switches*. Figure 14–4 shows centerbreak switches, in which the switch blades also move parallel to the base of the switch. Centerbreak vee switches are more compact but are rarely used unless space constraints prevent the use of the other configurations.



Sidebreak switch blades rotate perpendicular to the plane of the diagram
(horizontal upright mounting only shown)

Figure 14–3. Sidebreak switch configurations



Blades rotate perpendicular to the plane of the diagram
(horizontal upright mounting only shown)

Figure 14–4. Centerbreak switch configurations

c. Technical Reference Numbers. Tables 1 and 2 in ANSI C29.9 provide the standard mechanical and electrical strength combinations of apparatus insulators and assign them a technical reference (TR) number based on BIL voltage. Many switch manufacturers use the TR number to indicate the mechanical and electrical properties, the BIL voltage, and nominal dimensions for a given product.

(1) Example: A 230 kV disconnect switch rated for 900 kV BIL uses TR 304 insulating posts. But a vertical installation may require a higher cantilever strength of the posts, leading to selection of. This increases the diameter of the insulating posts for physical strength, but they have TR 308 essentially the same dimensions overall.

(2) Do not arbitrarily select a higher BIL rating than necessary. A TR 312 insulator is good for 1,050 kV BIL and has the same cantilever, torsional, and compressive

strength as a 900 kV BIL TR 304 insulator; however, the TR 312 is 12 in (30.5 cm). taller than the TR 304 and may violate requirements for clearance from existing bus or bus supports when placed on existing disconnect switch supporting structures.

d. Ground Switches.

(1) A ground switch may be an integral part of a disconnect switch. Whatever is connected to the contacts at the jaw end of the main disconnect switch will be grounded when the ground switch blade closes, engaging the jaw end of the main disconnect switch, because the hinge end of the ground switch blade is solidly grounded. Typically, the contacts at the jaw end of the main disconnect switch connect to a bus or transmission line of at least one phase, but preferably to all three phases using three ground switches connected to the same ground switch operator (which is separate from the disconnect switch operator).

(2) The ground switch may be used to provide a safety ground for the line or bus when the line or bus is de-energized for inspection or maintenance of equipment. It is used mainly where there is no local line breaker, in which case a remote PMA/utility breaker under control of others must be opened to keep the line safely de-energized. If the remote breaker is inadvertently closed, the closed ground switch will immediately cause the line relaying to trip the breaker because the line becomes solidly grounded.

(3) The ground switch blade operating mechanism must be interlocked with the disconnect switch blades to prevent the ground switch from being operated while the disconnect switch is in the closed position. This prevents a disconnect switch from closing on a grounded line, and likewise prevents a ground switch from closing on an energized line. Switch manufacturers typically provide mechanical interlocking as a standard feature; however, this interlocking should still be specified as a required feature of the switch assembly.

(4) BUPPO stands for “backup protection, pneumatically operated.” BUPPO ground switches were typically used in remote locations for protective relaying to force a ground-fault trip of a remote breaker when the BUPPO switch received a trip input. This might occur when a fault on the low-voltage side of a transformer might not be detected by the remote line relaying. These switches required only an input signal of some kind to trip the pneumatic switch operator without the need for electrical power. However, this method of protection was not selective because the entire line and all connected loads were tripped. The switch had to be manually reset later by a line crew once the problem was cleared. BUPPO switches are rarely specified anymore, in favor of breakers or circuit switchers with remote operating capability and selective relaying.

e. Operating Mechanisms. Disconnect switches have an operating mechanism for the disconnecting blades. If a ground switch is part of the switch assembly, a separate operating mechanism for the ground switch is provided. Operators for either type of switch may be manual or motor operated.

(1) *Manual Operated Mechanisms*. Geared-type manual operators driving a worm or bevel gear operated with a crank are the preferred standard for USACE switchyards. Lever-type manual operators without cranks and gearing are typically intended for switches of lower voltage and amperage ratings where less physical force is required to operate the switch. Lever-type manual operators should not be used.

(2) *Motor Operated Mechanisms*. A motor-operated mechanism must be specified if remote operation of the disconnect switch is required and is typically provided if the

disconnect switch is used to sectionalize a main bus or an auxiliary bus. Motorized switches are referred to as MODs, for “motor-operated disconnect” switch. Larger than normal phase spacing on higher voltage ratings may require separate operators synchronized for simultaneous blade operation.

f. Arcing Horns. Arcing horns help enable a disconnect switch to interrupt the magnetizing current of unloaded transformers or the charging current of unloaded transmission lines. These currents may be present at the switch terminals after the transformer or line has been unloaded but before the switch opens. All disconnect switches have some type of arcing horns to move the first and last arcing point off of the main contacts. Some switches have extended horns, whips, and other devices to increase the switch’s current interrupting rating from small values to larger ones. All switches have limits for what currents they can pick up or drop without damage. In some cases, a surge resistor may be needed to reduce the energy of the arc.

(1) All disconnect switches for USACE switchyards should be specified with arcing horns. IEEE C37.30.1 Annex B provides guidance on the expected magnitude of these currents, based on the dimensions and clearances of the disconnect switch. Most typical expected currents are under 10 amps.

(2) Surge suppression resistors may be installed to reduce the frequency and magnitude of the arcs that occur when opening under transformer magnetization current, and they protect the transformer windings from the impulses caused by the arcing. At the time of publishing, there is limited commercial availability of switches with the option of factory-installed surge suppression resistors. If an engineering study determines that normal arc mitigation features such as whips or horns are not sufficient and that surge suppression resistors are required, sole-source justification may be required for procuring the switches.

g. Interlocks Between Disconnect Switches and Other Equipment. Interlocking between disconnect switches and other equipment is often necessary to prevent inadvertent closure where switching is necessary to isolate any given line or piece of equipment. Interlocks may be mechanical or electrical, although both types are often used to better regulate remote operation where remote operation is provided. Most manufactures offer dry contacts and auxiliary contacts in the switch operating mechanisms, whether manually operated or motor operated, to accommodate any desired electrical interlocking.

(1) The Kirk key interlock mechanism is the most commonly used mechanical interlocking method on circuit breakers and disconnect switches in USACE switchyards.

(2) Most disconnect switches are used to isolate circuit breakers after the breaker has opened. These switches must be capable of interlocking with the circuit breaker controls to prevent opening or closing a disconnect switch while the breaker is closed. The isolating disconnects must remain open for safety if work is being performed on the breaker, but must be closed when the breaker is ready to be returned to service.

(3) Where multiple PMA transmission lines are served by the switchyard, interlocking may be necessary between multiple disconnect switches to preclude having different transmissions lines connected together inadvertently and to avoid unsynchronized paralleling of sources.

h. Disconnect Switch Ratings. The primary industry standard for high-voltage disconnect switches is IEEE C37.30.1. Older legacy specifications may refer to

IEEE C37.32a, but that standard was withdrawn several years ago in favor of IEEE C37.30.1.

(1) Rated maximum voltage of the switch should not be less than that of the connected circuit breakers, transformers, or other associated equipment.

(2) Impulse withstand voltage (also known as BIL) rating of the switch should not be less than that of the connected circuit breakers or other associated equipment.

(3) Continuous current ratings are 600, 1,200, 1,600, 2,000, 3,000, or 4,000 amps. However, 245 kV are typically rated a minimum 1,200 amps, while 500 kV switches are typically rated a minimum 2,000 amps. Many manufacturers simply do not have standard offerings below these recommended minimums for these voltage ratings. Rated continuous current of the switch must not be less than that of the associated circuit breakers or other load interrupting equipment.

(4) Rated momentary current of the switch should not be less than that of the associated circuit breakers or load interrupters, and never less than the short circuit available on the bus. If the short circuit current available exceeds the momentary current of the conveniently rated continuous current switch, a higher continuous current switch may be needed to get the required momentary current rating to exceed the short circuit current available.

(5) One of the non-electrical ratings of great importance not usually considered for other electrical equipment is ice-breaking capability. The specifications should reflect the required ice-breaking capability suitable for the environment. Preferred ratings are 3/8 in. (10 mm) and 3/4 in. (20 mm) of ice thickness.

(6) Wind loading is another important rating covered by IEEE C37.30.2.

14–10. Circuit Switchers

A circuit switcher is a switching device with SF_6 interrupters, similar to a live-tank circuit breaker (described in the following paragraphs); however, it lacks some of the operating features of breakers. Circuit switchers are usually less suitable for higher short circuit currents. Vacuum interrupters may be available for 69 kV system voltages, but not higher voltage ratings.

a. Circuit switchers are typically installed on the high-voltage side of large transformers when high cost and/or little real estate preclude the use of a circuit breaker and disconnect switch. They are usually limited to local transformer protection and are rarely used as substitutes for line circuit breakers.

b. While circuit breakers may be readily equipped with two sets of BCTs, there are no such provisions on circuits switchers. Separate pedestal-mounted CTs are often required.

c. Circuit switchers may have integral disconnecting switch blades operated independently of the interrupter contacts. This may be used as an automatic motorized feature to isolate the transformer after fault interruption before the transmission line breaker recloses to restore the line.

d. Some circuit switchers/disconnects are available with integral ground switches, much like those for disconnect switches.

14–11. Circuit Breakers

This discussion focuses on SF_6 circuit breakers. Oil circuit breakers are no longer being manufactured, and most of those still in service are—or should be—scheduled to be replaced with SF_6 breakers. Vacuum interrupters for high voltages are only now in development. It may be several years before vacuum interrupter technology becomes suitable and affordable for voltages of 115 kV and higher.

a. Insulating Medium. SF_6 gas is used as an insulating medium in the interrupters of high-voltage circuit breakers because of its superior ability to extinguish the arc that normally results between the contacts of the interrupters when the circuit breaker is opened, while safely containing the energy released by the arc within the interrupter.

(1) Most interrupters are designed to compress the SF_6 gas and blow it across the arc as the interrupter opens, to help extinguish the arc. Circuit breakers using this principle are commonly known as "puffers."

(2) SF_6 gas is considered environmentally hazardous because it contributes to ozone depletion; however, the gas is not normally exposed to the atmosphere at any point throughout the life of the circuit breaker. On rare occasion, a circuit breaker may develop a leak of SF_6 gas, in which case a low pressure or gas density alarm alerts maintenance staff long before the loss can pose an environmental hazard.

b. Types of Construction. Circuit breakers are classified as dead tank or live tank.

(1) Dead tank circuit breaker interrupters are enclosed in grounded vessels (tanks). The tanks are at ground potential (dead) when the interrupters are energized because the live bus connects to the interrupters through insulated bushings. Dead tank circuit breakers may therefore be installed at grade level, making it easier and safer to replace the interrupters if necessary.

(2) Live tank circuit breaker interrupters are enclosed in separate ungrounded vessels (tanks) at a potential above ground (live) when the interrupters are energized, because the live bus connects directly to terminals on the interrupter tanks. Although these tanks are insulated, high voltage is still connected across them. Live tank circuit breakers must therefore be installed on insulated structures high above grade.

(a) Live tank circuit breakers are typically less expensive than equivalent dead tank circuit breakers; however, live tank circuit breakers usually do not accommodate BCTs and require free-standing CTs mounted separate from the circuit breaker, adding cost and space needs on the switchyard.

(b) Live tank circuit breakers are usually vertical in configuration and may be less suitable for seismically active regions.

(3) Figure 14–5 provides an illustrated comparison of live tank and dead tank circuit breakers.

c. Bushings. High-voltage circuit breaker bushings are covered by IEEE C37.017. Legacy specifications written before the introduction of C37.017 might refer to one of the older IEEE C57 standards for outdoor power transformer apparatus bushings.

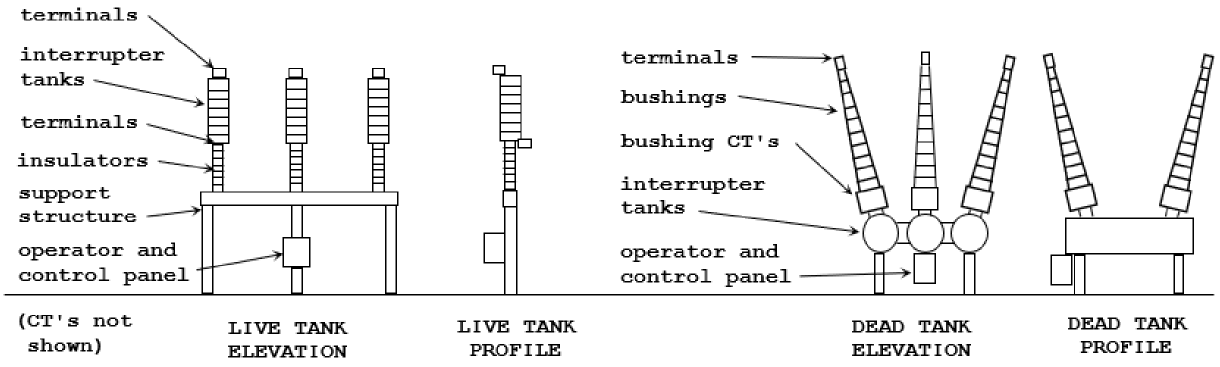


Figure 14–5. Comparison of live tank and dead tank circuit breakers

d. Bushings. High-voltage circuit breaker bushings are covered by IEEE C37.017. Legacy specifications written before the introduction of C37.017 might refer to one of the older IEEE C57 standards for outdoor power transformer apparatus bushings.

e. Test Terminals. Test terminals, also known as Doble test terminals, are used to allow electrical access to the bushings without having to disconnect the bus from the bushing terminal. The test terminal is attached to the bushing lug, and the conductor then attaches to the test terminal. The test terminal essentially acts as a miniature local means for disconnecting the current path.

(1) Without test terminals, if the bus is not disconnected from the bushing terminals, the bushing test must include whatever length of bus is between the bushing terminal and the open disconnect switches. If the bus remains connected to the bushing terminal, the magnitude of error on the bushing test depends on the bus material and size.

(2) Test terminals are relatively expensive and do not need to be specified unless the length of bus between the disconnect switch terminal and the breaker bushing terminal exceeds 30 ft (9.1 m). The switchyard maintenance staff should also be consulted in case operating policy requires test terminals on circuit breaker bushings regardless of this length of bus.

f. Porcelain Versus Non-Ceramic. Gas-filled porcelain bushings are an explosion risk. Oil-filled porcelain bushings have been known to fail when damaged by a sudden structural impact. Non-ceramic bushings (polymer or composite) are offered as an option by most manufacturers on most models and ratings of circuit breakers; however, non-ceramic bushings tend to be more expensive than porcelain at voltages under 362 kV.

(1) Porcelain and glass are essentially immune to ultraviolet deterioration, while non-ceramic polymers may eventually become brittle and degrade under stress.

(2) Some PMAs (also referred to as the utilities connecting to the switchyard) require the use of non-ceramic bushings because of their non-explosive properties. New installations should use composite insulators unless there is a requirement to match existing glass or porcelain insulators. Verify any preferences or restrictions with the operating project and the PMA.

g. *Operating Mechanisms*. There are three types of operators recognized: hydraulic, pneumatic, and electric. Each type of operator must meet the same IEEE performance standards. Preferred hydropower practice is to specify electric operators using 125VDC since that source is backed by the station battery and does not depend on ancillary pumps or compressors.

h. *Duty Cycle*. Duty cycle refers to the time required between consecutive close-open (CO) operations under short-circuit conditions and is addressed by IEEE C37.04. The standard is usually 0.3 seconds or 15 seconds, depending on the application of the breaker. The circuit breaker must be capable of performing a CO operation and repeating it after either 0.3 seconds or 15 seconds under short circuit conditions without degradation of performance.

(1) The 15-second interval is for a duty cycle where rapid reclosing of the circuit breaker is not required after a fault is cleared and is typical for most USACE switchyard circuit breakers.

(2) For critical loads where power essentially cannot be interrupted, a rapid reclosing circuit breaker is needed, in which case the time interval for this duty cycle reduces to 0.3 seconds. Rapid reclosing circuit breakers are more expensive and should not be specified unless specifically requested by the PMA. Breakers with automatic reclosing are not recommended for use near hydropower generating stations due to the risks of possible damage to generators.

i. *Control Equipment*. Breakers typically require 125VDC for the charging motor (considered a critical load requiring station battery backup) and alarms, and 120VAC for cabinet light and heaters. If SF_6 tank heaters are required, they may need 208-volt or 230VAC power; if so, large switchyard upgrades replacing several oil circuit breakers (OCBs) with SF_6 breakers may require a station service upgrade to support the net total additional power needed.

j. *Instrument Transformers*. Switchyard circuit breakers rely on CTs for relay protection. Voltage transformers may be required for metering or other utility relaying, but are almost always separate units. CTs may also be separate units but are typically on the circuit breaker bushings (in this case they are referred to as bushing current transformer [BCTs]).

k. *Relays*. Most relays are located in the powerhouse control room. A few relays may be located at the circuit breaker to provide basic automatic control and alarm functions for the breaker. These may typically be the following.

(1) Incomplete sequence timer (device number 62) with a lockout relay (device number 86) to prevent any further attempts to operate the breaker in the event of an incomplete breaker operation.

(2) A pressure relay (device number 63) to alarm the breaker in the event of low gas pressure (or temperature-compensated pressure that approximates density). Older breakers that may not have been able to withstand nominal voltage with no gas pressure were wired by some manufacturers to automatically trip on loss of gas; however, this disrupts service from the switchyard. Other breakers may be incapable of interrupting rated current at zero gas pressure and may be blocked from tripping. The no-gas pressure limitations of the breakers must be carefully considered in switchyard operation and protection.

l. Trip Coils and Capacitive Trip. Two trip coils (for redundancy) should be provided in breakers rated 245 kV and above. Some manufacturers provide this as standard even if not specified. The redundant trip coil may be connected to a capacitive trip device, which could trip the circuit breaker open if control power is lost; however, plants without medium-voltage generator breakers must rely on the switchyard breaker to serve as the unit breaker, in which case a trip could result in a plant backout. This must be coordinated with plant operations.

m. Spare Contacts. Power circuit breakers (device no. 52) have contacts to provide a breaker open or closed status signal to the coils and relays within the breaker. Spare contacts are provided for connection to external alarms and relays after the breaker has been installed.

(1) Contacts that are normally open when the breaker is open and closed when the breaker is closed are referred to as 52a contacts.

(2) Contacts that are normally closed when the breaker is open and open when the breaker is closed are referred to as 52b contacts.

(3) Contacts that are closed only when the breaker is in between fully open and fully closed are referred to as 52ab contacts.

(4) The specification must require a minimum number of spare 52a and 52b contacts to provide the intended external alarm and relay functions for the installed breaker. At least 10 percent additional spares of each type are recommended for unforeseen or future use.

(5) If the number of required spare contacts exceed what the manufacturer normally provides, the manufacturer often includes an auxiliary relay to provide the required number of spare contacts.

n. Cabinet Heaters. Cabinet heaters, also referred to as strip heaters or unit heaters, are almost always required in the local breaker control cabinet in the switchyard to prevent the accumulation of moisture in the control components. The heater wattage requirement varies based on geographic location and climate. The manufacturer should design the heater based on the specified service conditions of the circuit breaker.

o. SF_6 Tank Heaters. In operating conditions where ambient temperatures below -30 °C (-22 °F) can occur, the breaker pole tanks must be equipped with thermostatically controlled tank heaters to prevent the SF_6 gas from liquefying. This is a standard option available from breaker manufacturers.

p. Circuit Breaker Ratings. Ratings for high-voltage circuit breakers are described in great detail in IEEE C37.04 and IEEE C37.06. These standards should be checked to verify any changes before specifying a breaker. Test requirements are described in IEEE C37.09. Guidance for applications are provided in IEEE C37.010 and IEEE C37.011. The IEEE preferred ratings for circuit breakers are shown below.

(1) Voltage ratings for high-voltage circuit breakers are 72.5, 123, 145, 170, 245, 362, and 550 kV. ANSI C84.1 classified 345 kV and 500 kV systems as EHV. At present, USACE does not have any EHV breakers, but some USACE GSU transformers and 550 kV-rated disconnect switches at takeoff structures connect at 500 kV to PMA/utility-owned switchyard breakers off site.

(2) Dielectric ratings are 350, 550, 650, 750, 900, 1,300, and 1,800 kV. These are also known as BIL, withstand, or lightning impulse voltages.

(3) Continuous current ratings are 1,200 (up to 145 kV only), 2,000, 3,000, 4,000, and 5,000 (for 170kV and up) amperes rms.

(4) Short-circuit current ratings are 20 (for 72.5 kV only), 31.5, 40, 50, 63, and 80 (for 145 kV to 245 kV only) kA rms symmetrical. This may also be referred to as the interrupting rating. If a 123 kV circuit breaker is required with a short-circuit current rating above 63 kA, a 145 kV circuit breaker may likely be submitted by the manufacturer to take advantage of an established and tested design.

q. X/R Ratio. The X/R ratio is the ratio of the reactive impedance to the resistive impedance of the system at the point in which the circuit breaker is installed when experiencing a fault. Although not technically a rating, the X/R ratio of the system connected to the circuit breaker must be considered.

(1) The short circuit ratings in IEEE C37.06 are based on a symmetrical current basis, and IEEE C37.010 indicates a maximum X/R ratio of 17 for the asymmetrical component. The short circuit current waveform ideally crosses zero as soon as the circuit breaker contacts are open, and the arc may be more readily extinguished.

(2) Most circuit breakers used within the range of 72.5 kV to 550 kV open within three cycles or sooner. However, for X/R ratios greater than 17, the asymmetrical component of the short circuit current waveform may decay much slower than what the circuit breaker is normally designed for. The waveform will not cross zero until several cycles after the contacts have opened, thus prolonging the arc and risking damage to the contacts. See Figure 14–6.

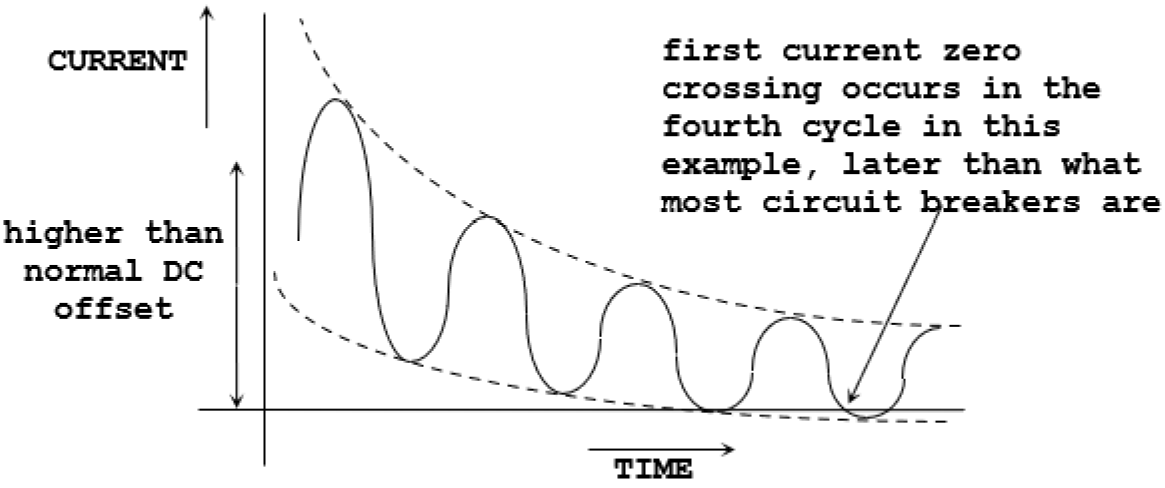


Figure 14–6. High X/R effect on a short circuit

(3) If the X/R ratio exceeds 17, the manufacturer must be made aware of this in the specifications to allow possible adjustments necessary in the prototypical design of the circuit breaker. ANSI/IEEE standards allow derating considerations under various conditions that manufacturers will consider.

r. Closing and Latching Current. The close and latch capability of a circuit breaker is the ability of the breaker to be closed onto a faulted system and stay closed to allow the fault to be cleared downstream. This may also be referred to as momentary current. Usually expressed in terms of kA peak, but may also be expressed as kA rms. For 60 Hz, the rated closing and latching current (kA, peak) of the circuit breaker is 2.6 times the rated short-circuit current. If expressed in terms of kA, rms total current, the equivalent value is 1.55 times rated short-circuit current.

s. Rated Interrupting Time. The maximum time interval to be expected during a circuit-breaker opening operation between the instant of energizing the trip circuit and the interruption of the main circuit on the primary arcing contacts under certain specified conditions. Usually expressed in terms of milliseconds but may also be expressed as cycles for 60 Hz breakers.

(1) For breakers rated 72.5 kV, this is either 50 ms (3 cycles) or 83 ms (5 cycles).

(2) For breakers rated 123 kV, this is 50 ms (3 cycles).

(3) For breakers rated 145 kV to 362 kV, this is either 33 ms (2 cycles) or 50 ms (3 cycles).

(4) Breakers rated 550 kV and higher must have an interrupting time of 33 ms (2 cycles). Verify that the breaker specifications have an interrupting time consistent for the rated voltage of the breaker.

t. Transient Recovery Voltage Considerations. TRV for high-voltage circuit breakers is the voltage that appears across the breaker contacts immediately after current interruption. Although more typical at extra-high voltages, 230 kV breakers and sometimes even 115 kV breakers may require TRV capacitors. Interrupting high fault currents can result in transient recovery voltages across the open contacts that exceed the dielectric strength of the gap, resulting in a flashover across the breaker contacts and possibly to ground inside the interrupter. IEEE C37.011 provides guidance on calculating expected levels of TRV. Rated and related TRV capabilities are also described in IEEE C37.04 and given in detail in IEEE C37.06. Some breaker manufacturers may provide TRV capacitors even if not explicitly required in the specifications to satisfy IEEE recommendations or internal design practices.

u. Spare Parts Considerations. Most switchyard breaker specifications include a list of spare parts, such as interrupters and operating mechanisms, and other field replaceable components. However, SF_6 interrupters and their operating mechanisms comprise the greatest part of most modern SF_6 circuit breakers and are not typically serviceable in the field. Depending on the ratings, some manufacturers of SF_6 breakers have determined it is less expensive to provide a complete spare circuit breaker instead of the individual components typically listed. If a spare breaker is specified, verify that it is included in the testing requirements along with the breakers intended for installation.

14–12. Instrument Transformers

Relays and meters typically cannot directly measure the utilization voltage and current of the power system. Instrument transformers measure these utilization values and provide an equivalent of typically 120 volts AC or 5 amps maximum for relays and meters. Instrument transformers are covered by IEEE C57.13. For switchyard applications, they are typically single-phase devices, pedestal-mounted, with an oil-filled bushing between the bus terminals and the instrumentation sections. Instrument transformers follow the same voltage and withstand ratings as do circuit breakers, and are tabulated in IEEE C57.13 Table 2. For a helpful interpretation of IEEE C57.13 requirements in general, see RUS Bulletin 1724E-300 Chapter 5.

a. *Voltage Transformers*. Voltage transformers had been commonly referred to as PTs; however, the official nomenclature used in IEEE C57.13 is “voltage transformer” and is abbreviated as VT. Switchyard VTs are stand-alone equipment located near the breaker or transformer where the voltage is being monitored, or at some point on a bus serving multiple breakers or transformers. Often, a single VT is placed on a main bus B-phase for synchronizing the connected breakers between the powerhouse and the PMA/utility system.

(1) *Voltage Ratings*. The voltage rating and BIL of voltage transformers are shown in IEEE C57.13 Table 16 for Group 3 outdoor VTs. Voltage transformers are applied from line to ground. Note that for 115 kV systems, BIL ratings of 450 kV and 550 kV are listed; however, USACE switchyard practice is to select the 550 kV BIL rating for 115 kV systems.

(2) *Thermal Rating*. The thermal rating is a measure of how many volt-amperes of burden the voltage transformer can carry at rated secondary load without exceeding the required temperature rise. Typically, an increase in thermal rating increases the physical size required of the voltage transformer.

(3) *Accuracy Classification*. The ANSI accuracy classification is a measure of how much error a voltage transformer might exhibit while operating within 90 to 100 percent of rated voltage for metering purposes. See paragraph 9–5 for additional information on accuracy classes.

(4) *Capacitive Voltage Transformer (CVT)*. VT by itself implies an inductive voltage transformer with a primary winding rated the same as the HV line, typically 115kV maximum. But at higher voltages, this requires very large windings and becomes prohibitively expensive. Capacitive coupling puts capacitors in a series string to act as a voltage divider and allows the voltage to drop from the primary voltage to a lesser value in the range of 5 to 10 kV so that a smaller, less expensive inductive transformer can be used to generate the metered signal. The secondary voltage supplied by the smaller inductive transformer is usually 120 volts or 67.5 volts for metering or relaying.

(5) *Capacitively Coupled Voltage Transformer (CCVT)*. Also known as CCPD (for potential device).A CCVT typically is used to couple power line (carrier) communications for relaying or other signals that transfer between switchyards. Since USACE does not own any of the transmission lines, USACE switchyard operations typically do not involve CCVTs or carrier signals. Such devices are usually provided and used by the PMA or local utility.

b. *Current Transformers*. CTs are commonly abbreviated as CT. Switchyard circuit breakers typically have BCTs for relaying and indication, mounted outside the breaker, and located inside the cylindrical housings at the base of each bushing. These CTs need only have an insulation level of 600 volts. For PMA revenue metering or main bus relaying or metering, stand-alone CTs rated for line voltage are more often used. This discussion focuses on high-voltage stand-alone CTs.

(1) *Voltage Ratings*. The voltage rating and BIL of CTs are based on system voltage as shown in IEEE C57.13 Table 2.

(2) *Continuous Thermal Rating*. IEEE C57.13 recognizes continuous thermal current rating factors between 1.0 and 4.0. USACE practice is to require a thermal

rating factor of 1.33, meaning the CT can operate continuously without overheating while 133 percent of primary current flows through it. This is to guard against accumulated heat damage from occasional high or sustained overcurrents. Higher thermal rating factors are more expensive and physically larger and should not be required if the ratio is properly selected.

(3) *Short-Time Thermal Current Rating*. The short-time thermal current rating of a CT is the rms symmetrical primary current that can be carried for 1 second with the secondary winding short-circuited without exceeding the limiting temperature in any winding.

(4) *Current Ratio*. IEEE C57.13 lists many standard current ratios, depending on whether the secondary windings are single-ratio type or multi-ratio type. A multi-ratio CT has one single core with secondary taps to provide a selection of ratios. See paragraph 9–5 for additional information on CT ratios.

(5) *Relaying Accuracy Classification*. The relaying accuracy rating is a measure of how many volts the CT can produce across the standard burden associated with the accuracy class at 20 times the rated current, while still operating with a ratio error of not more than 10 percent. See paragraph 9–5 for additional information on relaying accuracy classifications.

(6) *Metering Accuracy Classification*. The metering accuracy rating is a measure of the percent ratio error of a CT at a given standard burden imposed on the CT at 5 amps rated load. This is expressed as a number (metering accuracy class or percent ratio error), followed by a B (for burden), followed by a number (rated burden or ohms impedance of the CT circuit). See paragraph 9–5 for additional information on metering accuracy classification.

c. *Combined VT/CT*. Several manufacturers offer products combining a CT and a VT in the same package. These are not common in USACE switchyards and should not be used unless lack of space in the switchyard and otherwise unobtainable voltage clearances force the use of a combined VT/CT. A failure of either device could result in loss of both devices.

d. *Instrument Transformer Grounding*. Instrument transformer secondaries must be grounded at only one point, to prevent circulating currents and to avoid using the station ground bus as part of the secondary circuit. IEEE C57.13.3 recommends that the grounding point be physically closest to the first point of application of the secondary circuit. This point is usually where the protective relays and meters are located.

14–13. Surge Arresters

Surge arresters are voltage-limiting devices used to protect electrical equipment from voltage spikes in a power system. Surge arresters are also known as lightning arresters, as their primary objective was to protect electrical insulation from lightning strikes on the system. The more generic term “surge arrester” is now used to encompass overvoltage conditions that can occur from numerous other sources, such as switching operations and ground faults.

a. *Surges*. Lightning strikes result in a fast rate of rise because of the high magnitude and short duration of the strike, while switching operations result in a relatively slow rate of rise because the energy is stored in the electrical and magnetic fields of the system. Depending on the configuration and grounding of the system, a single line-to-ground fault may cause system voltage on the unaffected phases to escalate. Surge arresters are covered by IEEE C62.11. Application of surge arresters is covered by IEEE C62.22.

b. Types of Surge Arresters.

(1) *Spark Gap*. The first lightning arresters were nothing more than a spark air gap with one side connected to a line conductor and the other side connected to earth ground. When the line-to-ground voltage reached the sparkover level, the voltage surge was discharged to earth ground. These “rod-gaps” are still used in some transmission systems for end of line overvoltage protection. An advantage of the rod gaps is that they can be set to sparkover at lower voltages to protect people working in the area of energized lines.

(2) *Silicon Carbide*. Older surge arresters generally consist of silicon carbide resistor blocks in series with air gaps. These arresters normally carry minimal current and have a single voltage rating. Many such arresters are still in service, but are prone to seal leaks and moisture ingress affecting their reliability. USACE practice is to replace existing silicon carbide arresters with modern metal oxide varistor (MOV)-type arresters whenever the opportunity arises.

(3) *Metal Oxide Varistor*. Modern surge arresters contain blocks of a variable-resistance material, usually zinc oxide, with no air gaps. Line-to-ground voltage is applied continuously between the line and ground terminals of the arrester. These arresters carry a minimal leakage current that can be withstood on a continuing basis.

c. Surge Arrester Classes. Surge arrester performance is reflected by the class of arrester. The most common classes are discussed below for informational purposes, but only one class is recommended for USACE switchyards.

(1) *Station Class*. Station class arresters are designed to protect equipment that may be exposed to significant energy due to line switching surges and at locations where significant fault current is available. Their energy absorption capabilities are greater than other classes, and thus provide high reliability operation in switchyards. USACE switchyard practice is to specify only station class arresters.

(2) *Intermediate Class*. Intermediate class arresters are designed to provide economic and reliable protection of medium-voltage class electrical power equipment. Intermediate arresters are commonly used for the protection of dry-type transformers, for use in switching and sectionalizing equipment and for the protection of underground rural distribution (URD) cables.

(3) *Distribution Class*. Distribution class arresters can be found on smaller liquid-filled and dry-type transformers 1,000 kVA and less. These arresters can also be used for application at the terminals of rotating machines below 1,000 kVA, if available in the proper voltage rating. The distribution arrester is often used on exposed lines that are directly connected to rotating machines.

d. Grading Rings. Grading rings are not to be confused with corona rings. Grading rings are used on surge arresters to distribute the electrical stresses more evenly along the length of the arrester. Without grading rings, upper sections of zinc oxide blocks will be heated more due to non-uniform axial voltage sharing between sections of the arrester. Grading rings are not addressed by IEEE C62.11 or IEEE C62.22, but both leave it to the manufacturer’s discretion to use them if deemed necessary to establish desired ratings during factory testing.

(1) If grading rings were used to establish ratings, the manufacturer must provide the same design of grading rings along with the arresters.

(2) Manufacturers typically provide grading rings if the arrester length exceeds 5 ft (1.5 m) in length, typically on systems 170 kV and higher.

(3) By contrast, corona rings look the same as grading rings but may be smaller in circumference and are installed to encircle just the conductor or terminal. Corona rings are used when very high voltage can cause corona from sharp points or bends in the conductor or its connection. Surge arresters on systems below 500 kV do not typically need corona rings.

e. Surge Arrester Voltage Rating.

(1) Metal oxide has many advantages as a surge protector, but it is somewhat more complicated to apply correctly than older surge arresters.

(2) Maximum continuous operating voltage is defined as the maximum designated rms value of power-frequency voltage that may be applied continuously between the terminals of the arrester (as reflected in Table 1 of IEEE C62.11). The arrester rating is selected so that the maximum continuous power system line-to-ground voltage applied to the arrester is less than, or equal to, the arrester’s MCOV rating. To allow voltage fluctuation in the absence of PMA/utility data confirming highest voltages experienced over time, the calculated line-to-ground system voltage should be increased by 10 percent to obtain the desired rating for MCOV.

f. Insulation Coordination Study. An insulation coordination study per IEEE C62.82.1 is recommended to determine the minimum acceptable MCOV and other arrester voltages during operation for specifying surge arresters to ensure adequate protective margins are applied to the protected equipment.

g. Surge Arrester Sizing for Transformers. Most large transformers in USACE switchyards and substations are solidly grounded wye at the high-voltage bushings, in which case arresters are sized for line-to-ground voltage. If the transformer high-voltage bushings are connected in an ungrounded delta configuration to a powerline tap, the arresters should be sized for line-to-line voltage. The reason for this is that in an ungrounded delta system, a ground fault can raise the ground fault voltage from line-to-ground voltage to line-to-line voltage. A second ground fault establishes a line-to-line fault.

h. Surge Arrester Protection Levels. Protection levels are not ratings but are performance characteristics of arrester’s ability to ride through voltage surges of differing waveforms over various time intervals for all combinations of MCOV and duty cycles. IEEE directs designers to refer to manufacturers’ curves and data to perform an insulation coordination study. However, IEEE C62.22 includes an informational table taken from the 1991 edition that tabulates typical ranges of characteristics for different voltage ratings, expressed in terms of per-unit MCOV, in the absence of manufacturers’ data. If data for a given MCOV falls below calculated requirements from the insulation study, the next highest MCOV should be selected. The primary measures of performance are listed below.

(1) *Front of Wave*. Front of Wave (FOW) is the higher of either the arrester sparkover for a front-of-wave lightning impulse voltage or the 0.5 microseconds discharge voltage at the classifying current as called for in Table 6 of IEEE C62.11. In

surge arrester specifications, the maximum FOW discharge voltage across the arrester at 10 kA for 0.5 microseconds should be expressed as a kV crest value.

(2) *Temporary Overvoltage*. TOV is a power-frequency overvoltage for time periods from 0.01 seconds to 10,000 seconds. IEEE C62.11 defines a “no prior duty” test which presumes that the arrester would not have absorbed energy prior to the TOV. This is usually the case for single line-to-ground faults. In surge arrester specifications, TOV no prior duty capability should be expressed as a kV value at one second and at 10 seconds.

(3) *Maximum Discharge Voltage, or Lightning Impulse Protection Level*. Lightning impulse protection level (LPL) is usually based on a pair of numbers. The first number is an index of the wave front, or the virtual duration of the wave front in microseconds. The second number is an index of the wave tail, or the time in microseconds from virtual zero to the instant at which one-half of the crest value is reached on the wave tail. Examples are 1.2/50 and 8/20 waves.

(a) The IEEE established the 8/20 wave as the required lightning impulse test for which manufacturers must provide data, but most manufacturers also provide data for other wave shapes.

(b) In surge arrester specifications, the maximum discharge voltage across the arrester with 8/20 microseconds discharge current wave should be expressed as a kV crest value at 5,000 amps, 10,000 amps, and 20,000 amps.

(4) *Pressure Relief Capability*. The purpose of the pressure-relief test is to demonstrate that arresters remain intact, or fall in a small area around the unit, for given fault currents during an end-of-life event. The fault-current levels range from a few hundred amperes to 65,000 amperes (standard for station class arresters). In surge arrester specifications, the required pressure relief capability should be 65 kA rms symmetrical.

14–14. Generator Step-Up Transformers and Autotransformers

USACE hydro generators produce power at medium voltages while delivering power to the PMA/utilities at high voltages. This requires large transformers to be part of the USACE-managed powertrain. See Chapter 11 for more in-depth discussion.

14–15. Miscellaneous Switchyard Equipment

Utility-owned switchyards typically have a variety of other features and equipment not usually used in USACE switchyards.

a. *Relay Houses*. Most USACE switchyards are close enough to the powerhouse to allow the protective relaying and metering to reside inside the powerhouse, which is the exception in the power industry. Most all PMA and utility switchyards and rural substations have a small building to house the protective relaying and metering, with lighting, HVAC, and a station battery system for backup. If this is required for a new USACE switchyard, consideration should be given to the many prefabricated standard buildings designed for this purpose.

b. *Wave Traps*. Wave traps, or line traps, are large drum shaped inductive/capacitive (L-C) filters in series with a high-voltage drop used in conjunction with CCVTs (see paragraph 14–12). The CCVTs with wave traps allow audio frequency signals to use the high-voltage lines as the communication path to the next switchyard, most often for power line protection (pilot relaying). Fiber optics are beginning to replace this method of communication between switchyards. Some USACE switchyards have wave traps, but the wave traps are typically owned, maintained, and operated by the PMA or local utility as part of the line relaying system.

c. Capacitor Banks. Some USACE switchyards may have shunt capacitor banks used for power factor correction and are automatically switched in and out of the transmission circuit as needed to maintain the most profitable power factor.

(1) If capacitor banks are present, they are typically owned and operated by the PMA or local utility. They provide a source of reactive power for fluctuating inductive loads.

(2) Capacitor switching places an additional burden on circuit breakers with TRVs. IEEE C37.06 addresses capacitive current switching ratings for breakers in the event capacitor banks are encountered in USACE switchyards.

d. Shunt Reactors. Power factor correction is sometimes needed to counteract the capacitive effect of lightly loaded transmission lines or lines consisting of capacitive cable (especially submarine cable). The capacitive effect can elevate the line voltage to dangerously high levels under certain operating conditions. In such cases, large shunt reactors are employed to counter the constant capacitive reactance. Shunt reactors are less likely to be switched in and out of service as are capacitor banks and are usually permanently connected if used. They may also be used for reactive neutral grounding of the system at the high-voltage neutral bushing of GSU transformers, instead of the more typical solid grounding of the neutral bushing.

e. Series Reactors. Some USACE switchyards may have series reactors to function as current limiting reactors to increase the impedance of a system and reduce the available fault current to equipment that may not be rated for such high fault current. Inserting a series reactor between high fault current sources and other equipment can allow the use of less expensive equipment with lower short circuit current ratings, or delay the forced replacement of lower rated equipment if system fault contribution levels rise. The use of series reactors to minimize the required short circuit ratings of downstream equipment is more often seen in medium-voltage distribution where station service taps are made at main unit generator leads as described in Chapter 15.

f. Gas-Insulated Switchgear. Some non-USACE switchyards employ gas-insulated switchgear (GIS), where the breakers, instrument transformers, and much of the bus are enclosed in SF_6 gas-filled fittings. The result usually resembles a large, isolated phase bus system. This design approach usually requires just a fraction of the real estate that a conventional air-insulated switchyard requires, but it is expensive and more maintenance-intensive. GIS breakers have separate guidelines in IEEE C37.06 and are not typical of USACE switchyards.

Chapter 15
Station Service

15–1. Power Supply

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

b. "Black Start" Capability.

(1) "Black start" capability is the ability to start a main generating unit to speed-no-load when there has been a loss of normal station service power from the grid and no main units are running, leaving the plant "black" except for emergency lighting. The unit is typically used to restore normal station service power without relying on the grid. This is a "plant" black start. If the grid has been lost, the process continues as a "grid" black start by energizing the GSU transformer and transmission lines.

(2) The associated Power Marketing Agencies have designated by mutual agreement with USACE some plants as black start plants (in this context, a grid black start). Select units at these plants require periodic testing of the black start process and are thus given the most priority by powerhouse staff for ongoing operability and reliability.

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

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

(5) Units subjected to a load rejection are designed to go to speed-no-load and continue running; however, they sometimes shut down completely.

(6) Black starting can take many forms. Some black start plants have a station service hydro unit continuously running and disconnected from the grid so they are not susceptible to grid disruptions. Some black start plants have a station service hydro units designed to start without any AC power available (have DC powered pumps, and/or thrust bearing lift pump is not required). Some plants use an automatic-start,

engine-driven generator for operating governor oil pumps. Black starting assumes DC power is available from the battery.

c. Multiple Sources for Station Service.

(1) Two station service transformers, each capable of supplying the total station load from an independent source, should be provided.

(a) Buses and switching should be configured such that each transformer can receive power from either the main unit generators or the transmission system (backfeeding power from the grid). Plants with just one station service transformer must have a standby engine-driven generator in case that one source of station power is lost.

(b) Although the Federal Energy Regulatory Commission (FERC) requires all reservoir projects to be equipped with an engine-driven generator for emergency standby service, the capacity of these emergency sources is usually limited to operation of the spillway or intake gate motors and essential auxiliaries in the spillway or intake structure. Such units should thus not be relied on to backfeed sufficient emergency station power to the powerhouse, as they may be undersized for the total load of both facilities.

(2) A unit that will be operated in a base load mode should be selected to supply a station service transformer. Station service source selection switching that allows supply from either a main unit or the grid (PMA power system through a GSU transformer) should be provided for normal station power. The switching should be done by interlocked breakers to prevent inadvertent parallel operation of alternate sources. If a main unit is switched on as a source, then the supply should not depend on that unit being connected to the grid. If the grid is switched on as the source, then the supply should not depend on any units being connected to the grid.

(3) Each supply and bus tie breaker should be electrically operated for remote operation from the control room in attended stations or a remote control panel near the switchgear. A second non-automatic bus tie breaker may also be used in series to assist isolation of the electrically operated tie breaker for maintenance by having the connected bus de-energized while the other bus on the opposite side of the manual tie breaker may safely remain energized. As a minimum, bus voltage indication for each bus section should be provided at the remote point where remote plant operation is provided. Transfer between the two normal sources should be automatic. Transfer to the emergency power sources should also be automatic when both normal power sources fail. Feeder switching is performed manually except for specific applications.

(4) Three-phase, 480/277-volt wye station service distribution systems using an HRG neutral are preferred for station service. The transformer neutral goes straight to the HRG with no 277-volt loads connected. Like the traditional ungrounded delta system, a wye/HRG system tolerates, and allows detection of, accidental grounds without interrupting service to loads while minimizing the ground fault current to a safe level, usually less than 10 amps. Ungrounded delta systems can experience high TRVs on the ungrounded phases, increasing the likelihood of phase-to-phase faults. A second ground fault in conjunction with the first ground fault, whether the system is delta or wye/HRG, could create a high-current, line-to-line fault through the ground path.

(5) Any emergency source should have automatic start control. The source should be started whenever station service power is lost. The emergency source control should also provide for manual start from the plant control point. It is also important to provide

local control at the emergency source for non-emergency starts to test and exercise the emergency source. A load shedding scheme may be required for any emergency source if the source capacity is limited.

(6) If available fault current at a main unit tap exceeds the interrupting rating of the station service switchgear (typically 63 kA max for new switchgear), current-limiting reactors are typically used to reduce fault current to less than the station service switchgear interrupting rating.

(7) See Figure 15–1 for an illustration that incorporates some of the features described above.

(8) MC switchgear with vacuum circuit breakers should be supplied for station service system voltage at or above 4.16 kV. For 15 kV switchgear, SF_6 gas-insulated breakers are another option, but SF_6 breakers typically require more maintenance involving gas analyzers and equipment for gas recovery that is not required for vacuum breakers. ME switchgear with electrically operated 600-volt drawout air circuit breakers should be used on 480-volt station service systems. The switchgear should be located near the station service transformers.

(9) Station service switchgear should have a sectionalized bus, with each section receiving power from a different normal station service source (usually a main unit bus tap) as depicted in Figure 15–1. These buses are typically referred to as Bus 1 and Bus 2. Distribution beyond this switchgear typically uses 480-volt switchboards or MCCs with designations reflecting their source as either Bus 1 or Bus 2.

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

(11) To reduce arc flash hazard levels, breakers should be equipped with an arc flash reduction maintenance switch. When engaged, the switch sets all protection settings to instantaneous in case of a fault, then restores all time-delay settings when disengaged. Remote breaker control panels are also recommended for mains and tie breakers as a minimum.

(12) Specifications for new breakers and breaker replacements should include a remote racking device.

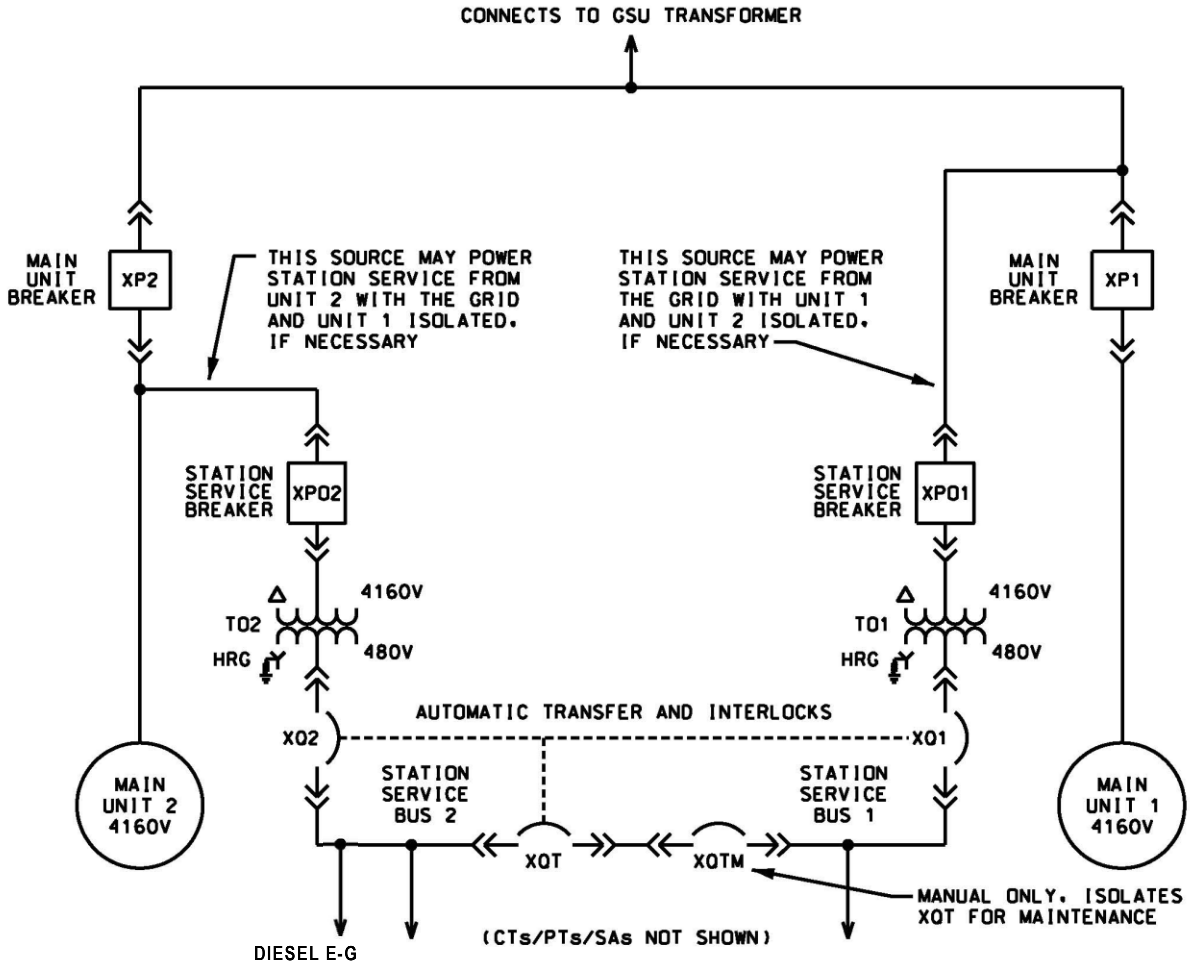


Figure 15–1. Example station service sources configuration, one-line diagram

d. Station Service Distribution System.

(1) In many plants, feeders to the load centers (ME switchgear, switchboards, or MCCs) can be designed for 480-volt operation. In a large plant, where large loads or long feeder lengths are involved, use of 13.8 kV or 4.16 kV distribution circuits are satisfactory when economically justified. Duplicate feeders (one feeder from each station service supply bus) should be provided to essential 480-volt load centers. Appropriate controls and interlocking should be incorporated in the design to ensure that both sources are not being closed onto the same bus anywhere in the system. Feeder interlock arrangements and source transfer should be made at the feeder sources where feasible, rather than at the loads.

(2) The distribution system control should be evaluated to ensure that all contingencies are covered, but in a cost-effective manner. The load centers should be located at accessible points for convenience of plant operation and accessibility for servicing equipment. Allowance should be made for the possibility of additional future loads (at least 10 percent).

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

(4) See Figure 15–2 for an illustration that incorporates the features described above.

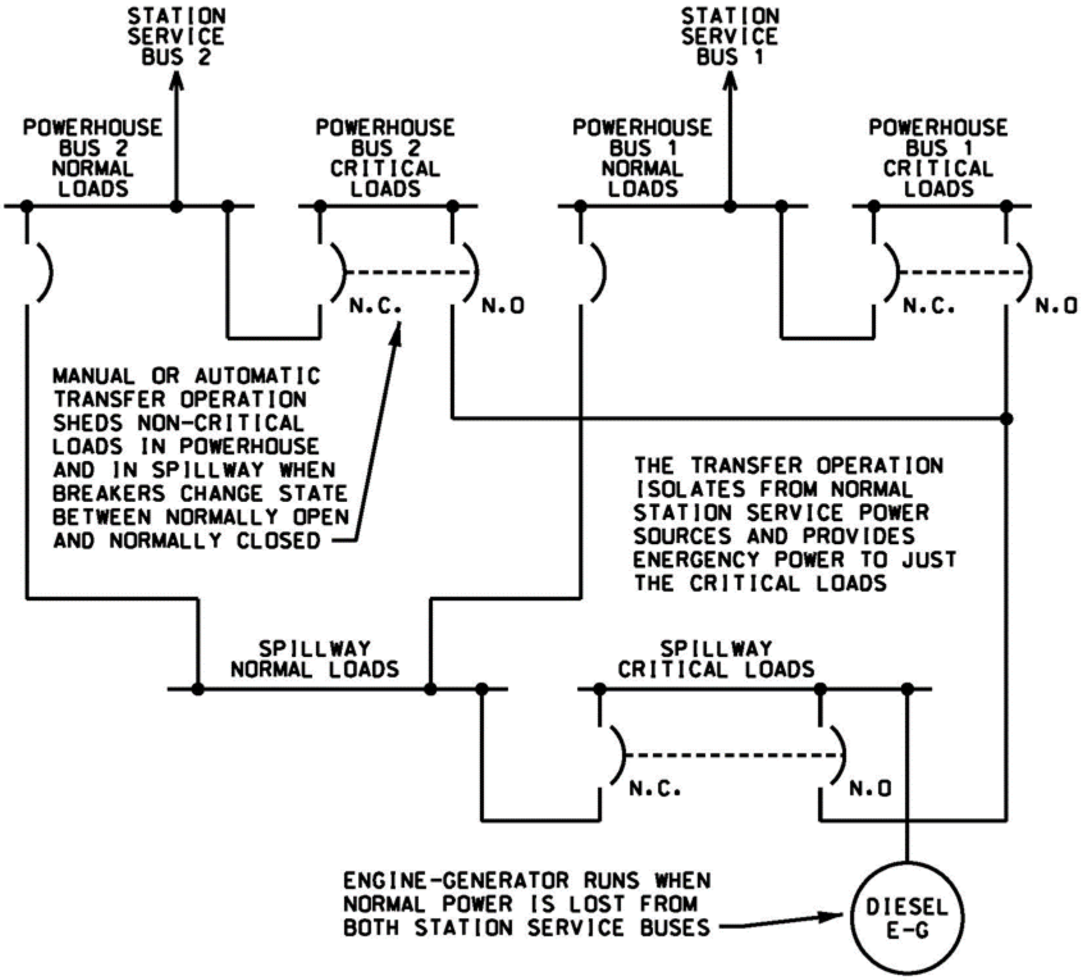


Figure 15–2. Example station service distribution configuration, one-line diagram

e. Emergency Power for Station Service.

(1) An automatic start emergency power source is recommended. Diesel engine-generators are most common and are available in a wider selection of kW ratings than propane. Installation of a diesel engine-generator could be inside an existing powerhouse room modified for the purpose, or outside the powerhouse in a weatherproof enclosure or new small building constructed for the purpose. Mechanical and structural engineers should be consulted for structural modifications necessary for

ventilation, and design for ventilation and fuel systems. See Chapter 2 for balance of plant considerations.

(a) If a diesel engine-generator is used, the engine must be exercised monthly by running it for several hours while loaded at roughly 75 percent. This is necessary to keep the fuel inlets clear of carbon buildup and thus provide better reliability. A load bank may be required to provide exercising under load if carrying station service loads cannot provide sufficient load for the exercise.

(b) Diesel fuel has a shelf life of not more than one year (see paragraph (c) below) and so must be burned off routinely in favor of fresh diesel fuel, whereas propane has an indefinite life; however, propane-driven generators are typically limited to 150 kW and below.

(c) The primary diesel fuel degradation mechanisms are hydrolysis, microbial growth, and oxidation. For diesel fuel purchase specifications, including the initial fill of the genset, consider requiring oxidation stability additives, less than 0.1 percent biodiesel, and no cetane improvers (which are inherently unstable).

(d) Keeping tanks as full as possible lessens exposure to water and other contaminants in the ambient air.

(e) Fuel polishing systems can filter the fuel, separate water, and perform periodic testing for acid number, oxidation stability, and microbes. A true bottom sample is imperative for good information regarding microbes, because water sinks to the bottom of the diesel tank.

(2) Load shedding of non-critical loads may be provided, leaving only the critical loads connected while the powerhouse is operated on the emergency diesel engine-generator. This can reduce the required size and cost of the engine-generator and fuel consumption. Non-critical load feeder breakers may be equipped with shunt trip devices to automatically trip on transfer to emergency power, but they must be manually reset later. The use of a split bus to separate critical feeder breakers from non-critical feeder breakers can make load shedding simpler by using automatic transfer switches or interlocked electrically operated breakers.

(3) Critical or essential loads are those that are required to maintain the critical powerhouse functions when running on emergency power (such as emergency lighting) essential main unit auxiliaries to start a unit, drainage, or unwatering pumps to keep the powerhouse from flooding until a normal source of station power can be restored. Other routine loads that can afford a prolonged outage are considered as normal, non-essential, or non-critical loads.

(4) Switching to connect emergency source power to one of the buses, or selectively, to either bus should be provided. If the emergency source is connected to only one bus, the reliability of the station service source is compromised since the bus supplied from the emergency source could be out of service when an emergency occurs. It is preferable that the emergency source be capable of supplying either bus, with the breakers interlocked to prevent parallel operation of the buses from the emergency source.

15–2. Relays

A protected zone should be provided for equipment and should overlap the associated breakers. The protective system should operate to remove the minimum possible amount of equipment from service for any fault.

a. Overcurrent relays on the supply and bus tie breakers should be set so feeder breakers trip on a feeder fault without tripping the source breakers.

b. Ground detection and alarm relays should be provided for both delta and wye/HRG systems. The relaying/alarm function may be part of the HRG system itself or may be provided by multi-function digital relays using HRG input.

c. Bus differential relays should be provided for station service systems of 4.16 kV and higher voltage.

d. The adjustable tripping device built into the feeder breakers is usually adequate for feeder protection on station service systems using 480-volt low-voltage switchgear.

15–3. Control and Metering Equipment

a. Indicating instruments and control should be provided on or near the station service switchgear for local control. Three PTs connected in a grounded wye configuration should be used so that voltage-to-ground imbalances can be measured. A voltmeter, an ammeter, a wattmeter, and a watthour meter are usually sufficient for metering equipment.

b. A station service annunciator should be provided on or near the switchgear. SCADA capability should be provided with the watthour meters for remote indication of station service energy use. Additional auxiliary cabinets may be required for mounting breaker control, position indication, protective relays, and indicating instruments.

c. Modern practice typically provides the local breaker controls on a local panel near the switchgear to allow manual breaker operation without standing in the arc flash hazard zone in front of the breakers. For large plants, physical separation of control and relay cubicles should be considered so control and relaying equipment are not damaged or rendered inoperable by the catastrophic failure of a breaker housed in the same or adjacent cubicle.

15–4. Estimated Station Service Load

a. The maximum demand that is expected on the station service system is the basis for developing station service transformer ratings. The expected demand may be determined by listing all connected loads and their corresponding demand loads in kVA. A diversity factor may then be applied but should not be smaller than 0.75. During high-activity periods or plant emergencies, higher than normal station service loads can be expected, and if a small diversity factor has been used, the system may not have adequate capacity to handle its loads. An alternative to calculating demand in existing facilities is to measure actual loads over a one-year period and recording peak and average loads.

b. Demand factors used for developing station service equipment capacities can vary widely due to the type of plant (high head stand-alone power plant versus low head power plant integrated with a dam structure and navigation lock). Development of demand factors for unit auxiliaries should account for the type of auxiliaries in the plant based on trends observed at similar plants. For example:

(1) The governor oil pump demand for a Kaplan turbine is greater than that for the governor oil pump demand for a Francis turbine of the same output rating because of the additional hydraulic capacity needed to operate the Kaplan turbine blades.

(2) If the plant is base loaded, governor oil pumps do not cycle as often as governor oil pumps in a similar plant used for automatic generation control (AGC) or peaking service.

(3) Table 15–1 provides an example demand load estimate for a large plant. It assumes 1 hp as the equivalent of 1 kVA and, on lights and heaters, uses the kW rating as the kVA equivalent. The accuracy of the method is within the accuracy of the assumptions of demand and diversity. The values of demand and diversity factors correlate with trends observed in recent years on station service loads.

c. Station service systems should be designed to anticipate load growth. Anticipated growth depends on several factors, including size of the plant, location, and whether the plant will become an administrative center.

(1) A one- or two-unit isolated plant not suitable for addition of more units would not be expected to experience a dramatic increase in demand for station service power. For such a plant, a contingency for load growth of 20 percent is adequate. Conversely, some large multi-purpose plants have experienced 100 percent increases in the connected kVA loads on the station service system over original design requirements.

(2) Capacity deficits found in existing station service systems may have been caused by unforeseeable demands added over the years to provide service for off-site facilities added to multipurpose projects. Examples of this are the development of extensive maintenance and warehouse or navigation facilities outside the power plant, or electrical requirements resulting from environmental protection issues such as fish bypass equipment and fish hatcheries. The station service design should have provisions for unanticipated load growth for multipurpose projects with navigation locks and fish ladders. For such projects, a minimum growth factor contingency adder of 50 percent could be justified.

Table 15–1
Sample estimated station service load and recommended transformer capacity

Function	Number Units	Power	Connected Load kVA	Demand Load kVA
Unit Auxiliaries for 8 Units				
Governor Oil Pump				
Pumps on Bus #1	8 @	100 hp	800	400
Pumps on Bus #2	8 @	100 hp	800	
Pumps on Bus #1	4 @	25 hp	100	50
Pumps on Bus #2	4 @	25 hp	100	
Turbine Bearing Oil Pump				
Pumps on Bus #1	8 @	1 hp	8	8
Pumps on Bus #2	8 @	1 hp	8	

Function	Number Units	Power	Connected Load kVA	Demand Load kVA
Head Cover Pump	**Number Units**	**Power**		
Pumps on Bus #1	8 @	2 hp	16	16
Pumps on Bus #2	8 @	2 hp	16	
Thrust Bearing Oil Pump				
Pumps on Bus #1	8 @	10 hp	80	80
Pumps on Bus #2	8 @	10 hp	80	
Governor Air Compressor				
Compressors on Bus #1	2 @	15 hp	30	15
Compressors on Bus #2	2 @	15 hp	30	
Generator Housing Heater	8 @	18 kW	144	*
GSU Transformer Auxiliaries				
Transformer Cooling Fans	24 @	2 hp	48	24
Transformer Oil Circ. Pumps	8 @	2 hp	16	8
Station Auxiliaries				
High Bay Lights			100	100
Supply to Dam			700	300
Fire Pump			25	25
HVAC-Heat Pump			380	36
Battery Charger No. 1			20	20
Battery Charger No. 2			20	**
Preferred AC Inverter			10	10
Elevator			25	25
Power Outlets			–	25
Draft Tube Crane			50	0
Duplex Sump Pump			15	8
Powerhouse Crane			100	0
Air Compressor No. 1			20	20
Air Compressor No. 2			20	**
Lubricating Oil Purifier			14	14
Lubricating Oil Pump			5	0
Water Heater – 20 gal.			2	2

Function	**Number Units**	**Power**	**Connected Load kVA**	**Demand Load kVA**
Water Heater – 100 gal.			5	2
Machine Shop				
Largest Motor				15
Switchyard				
Cable Tunnel Ventilating Fan			5	5
Power Outlets			–	5
Lighting			40	30
Total, less heating			3,832	1,242
Total demand with diversity factor of 75 percent				932
Estimated total heating load				1,000
Estimated total demand load with heating				1,932
Recommended size of each station service transformer				2,000 kVA (Note 1)

Notes:
1. Each transformer should be sized to carry the entire powerhouse demand load when necessary.
* Not on when unit running
** Standby

Chapter 16
Primary Controls, Metering, Annunciation, and Sequence of Event Recorder

16–1. Scope

a. For the purposes of this chapter, “primary control systems” refers to all equipment for control and indication except for SCADA, which is covered in Chapter 18. Control systems consist primarily of PLCs, HMIs, hard-wired relay logic (such as auxiliary relays and timing relays), indicating and recording instruments, control switches, protective relays, and similar equipment.

b. Governor and exciter controls are a subset of the primary control systems, and details can be found in Chapters 7 and 8.

c. IEEE 1010 provide guidelines for planning and designing control systems for hydroelectric power plants.

16–2. Control Room

a. The control room is the centralized location for the supervision and control of the main generating units, generator breakers, high-voltage switchyard breakers or motor-operated disconnect switches, and station auxiliaries. Spillway gates, fishways, security systems, project communications, fire alarm control panels, and other project equipment control functions should also be located in the control room, when required.

b. To operate the powerhouse in the event of a SCADA outage and to validate SCADA data when necessary, there should be independent primary controls in the control room in addition to and separate from the SCADA system. These controls can include control switchboards, control consoles, or an independent PLC/HMI control system. The control room should be laid out ergonomically so the operator can easily switch between operation using SCADA and the primary control system.

16–3. Control Room Location

a. The control room location should allow ready access to the generator units and adjacent switchyard. The relative number and lengths of control circuits to the units and to the switchyard is a factor to consider but is secondary to operating convenience. The control room should be at an elevation above maximum high water, if there is any danger that the plant may be flooded. Control room location should be decided early in plant design since many other features of the plant are affected by the control room location.

b. Control location definitions and control modes are further described in IEEE 1010.

16–4. Unit Switchboards

a. Unit switchboards provide local manual control of the generator unit and are located near the controlled generator unit. The switchboards contain all the necessary control switches, meters, relays, and annunciators to allow an operator to safely operate and monitor the status of the unit.

b. Switchboard panels and doors should be 1/8-in (3.2 mm) thick or No. 11 U.S.Standard (USS). gauge (standard thickness) smooth select steel. Consider using a standard, modular, vertical rack mounting system for ease in replacing equipment over time.

16–5. Equipment Arrangement

a. Arrangement of control equipment on the switchgear, switchboard, or control console should be carefully planned to achieve simplicity of design and to replicate unit control placements familiar to the intended operating staff. Simplicity of design is a definite aid to ensure proper operation and tends to reduce operating errors; therefore, the relative position of devices should be logical and uniform.

b. Arrangement of control switches, meters, and mimic bus should simulate the relative order of interconnections or physical order of the plant arrangement, assisting the operator in forming a mental picture of connections. If a benchboard style control console is used, the top of the control console panel should be inclined to improve access to the control switches and to improve console visibility. The location of each control device should be based on its function(s), its relation to control devices for other items of equipment, and by its use by the operator.

c. HMI design and implementation should follow ANSI/International Society of Automation (ISA)-101.

16–6. Metering

a. A voltmeter, ammeter, wattmeter, varmeter, and watthour meter should be provided at each unit switchboard. Voltmeters and ammeters should be selectable by phase. CTs and voltage transformers used for generator revenue meters for generators 10 MVA and larger should have an accuracy class of 0.3 or better, as defined in IEEE C57.13.

b. Bi-directional revenue meters should include both energy (kWh) and reactive power (kVARh), and have an accuracy class of 0.1 or better, as defined in ANSI C12.20. Revenue metering accuracy should be coordinated with the utility.

16–7. Annunciation and Sequence of Event Recorder Systems

a. Every power plant should have annunciation and sequence of event recorder (SER) systems, or a combined system. The annunciation system should provide both audio and visual signals in the event of trouble or abnormal conditions. The SER system should log alarms and control actions for troubleshooting events. There should be redundancy in annunciation/SER systems such that the plant can still operate if a single system is down due to failure or maintenance. SCADA systems typically include annunciation and SER, which serves as redundancy, albeit at a lower SER resolution.

b. As much as practical, alarm points should be separated to provide operators specific information on the abnormal condition.

c. The SER should have a system clock and time synchronization. SER accuracy should be 1 msec or better for electrical fault events, and 10 msec or better for other alarms.

16–8. Generator Starting and Stopping Sequences

a. Each generator control system should include automatic starting and stopping sequencing logic, either using a PLC or hard-wired logic. The starting sequence begins with pre-start checks of the unit, followed by starting unit auxiliaries, and ends with the unit operating at the speed-no-load condition.

b. Automatic synchronizing capabilities should be provided and used under normal operation to reduce stresses on the generator. Manual synchronizing capabilities should be provided as a backup and for testing. Both automatic synchronizing and manual synchronizing should be supervised by a synchronism-check device.

16–9. Location of Power Plant Controls

a. *Large Power Plants*. For large power plants, centralized unit controls, indication, and annunciation should be provided in the control room to supplement or duplicate those on the local generator switchboard. Control switches should be provided to transfer control of any selected unit or group of units between the control room and the local generator controls.

b. *Small Power Plants*. For smaller power plants, the unit switchboards may be located in the control room. These controls had, at times, been installed on or near MC switchgear that were also located in the control room. However, locating controls near medium-voltage equipment should be avoided to reduce the safety risk to operators. Where the small plants are remotely operated from another facility, control transfer switches should be provided to select between local operation or remote operation.

Chapter 17
Electrical Protection

17–1. General

a. Protective relays include those devices that detect electrical faults or abnormal operating conditions. These devices may trip circuit breakers to isolate equipment and/or notify the operator through the annunciation system that corrective action is required.

b. A protective relaying system includes the protective relay, the sensing and status devices (inputs such as CTs and voltage transformers), auxiliary and/or lockout relays, and the circuit breakers. A failure of any component may cause the protection system to fail, therefore, an independent protective relay system should provide backup protection for all electrical equipment. For example, the GSU transformer and/or line protective relay systems should provide backup protection for a generator fault in the event of a generator protective system failure. Protective system zones should overlap, typically overlapping circuit breakers, so that no electrical equipment is unprotected.

c. Protective relay system designs must balance several factors. Designs should consider the following:

(1) Reducing single points of failure.

(2) Reducing complexity.

(3) Ensuring redundancy and reliability.

(4) Ease of maintenance.

d. The application of relays must be coordinated with partitioning the electrical system by circuit breakers, so the least amount of equipment is removed from operation following a fault, preserving the integrity of the balance of the plant's electrical system. Hand-reset lockout relays should be used to prevent re-energizing circuits before personnel have investigated the trip event and determined that equipment is ready for re-energizing.

e. Protective systems must be set, tested, and coordinated to meet applicable NERC PRC requirements:

(1) PRC-002: Disturbance Monitoring.

(2) PRC-005: Protection System Maintenance.

(3) PRC-019: Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection.

(4) PRC-024: Generator Performance During Frequency and Voltage Excursions.

(5) PRC-025: Generator Relay Loadability.

(6) PRC-026: Load-Responsive Relay Settings.

(7) PRC-027: Coordination of Protection Systems for Performance During Faults.

f. Multi-function digital protective relays should be used to reduce equipment and maintenance costs, and to provide improved protection, SER, and event recording.

(1) Separate independent protective relays should be provided for each power system component (such as generators, main transformers, and the high-voltage bus) for independent backup protection and for ease of maintenance.

(2) Separate differential relay protection for generators and transformers should be provided, even on unit installations without a generator circuit breaker.

(3) Test switches should be used to isolate relay I/O circuits for testing.

(4) IEEE C37.2 relay element numbers should be used in all documentation.

g. Protective relay settings should be developed based on system information available, such as equipment nameplates, electrical characteristics from tests, and fault studies. When protective relays trip, the events should be analyzed to determine whether operation was correct, and settings reviewed for adequacy based on the event.

(1) Settings that may operate based on faults external to USACE equipment must be coordinated with the utility.

(2) Settings should balance various factors, including speed, sensitivity, and selectivity. Relays should trip quick enough to minimize damage yet also not trip quickly for faults outside their zone (miscoordination) or for acceptable transient conditions (nuisance tripping).

17–2. Main Generator Protection

a. The general principles of relaying practices for generators are discussed in IEEE standards C37.101 and C37.102. The generator protection should be configured such that for a mechanical problem, such as high bearing temperature or low governor oil pressure, the generator breaker should not open until the wicket gates are at or below the speed-no-load gate position. Protective temperature relays should be provided, as discussed in Chapter 6. For hydroelectric generators rated above 1,500 kVA, the multifunction relay should include protection for:

(1) 21 – Distance (backup protection).
(2) 24 – Volts/Hertz.
(3) 25 – Synchronism check.
(4) 32 – Reverse power.
(5) 40 – Loss of field.
(6) 46 – Negative sequence.
(7) 51 – Phase overcurrent (alarm only).
(8) 51N – Neutral overcurrent (for reactor grounded units).
(9) 59 – Overvoltage.
(10) 64G – Stator ground (for high-resistance-grounded units).
(11) 64F – Field ground.
(12) 78 – Loss of synchronism.
(13) 87 – Differential.
(14) Breaker failure.
(15) Inadvertent energization.
(16) Loss of potential (alarm only).

b. For high-resistance-grounded generators, if the generator is directly connected to another unit, a timed sequential ground tripping scheme should be provided to isolate and locate generator grounds versus delta bus grounds.

c. The generator breaker failure scheme should be integrated into the digital relay to provide the operating logic. When the protective relay attempts to trip the breaker, then the current at the generator breaker CTs should stop flowing and the breaker should indicate as “open” within the breaker interrupting time. If, after a time delay, either current has not stopped flowing or the breaker still indicates as “closed,” then the breaker failure logic should trip backup circuit breakers.

17–3. Transformer Protection

a. The basic principles involved in transformer protection are discussed in IEEE C37.91. For transformers that connect to more than one generator, redundant relays should be provided. For transformers or transformer banks rated over 3,000 kVA, the multifunction relay should include protection for:

(1) 24 – Volts/Hertz.
(2) 51 – Phase overcurrent.
(3) 64/51N – Ground/neutral overcurrent.
(4) 87 – Differential.

b. Transformer winding temperature monitoring devices should trip breakers to unload the transformers when the transformer winding temperature reaches a point too high for safe operation. Temperature protection is important for forced-oil, water-cooled transformers that may not have any capacity rating without cooling water.

17–4. Bus Protection

a. The basic principles of bus protection are discussed in IEEE C37.234. Medium-voltage switchgear and high-voltage switchyard buses can be protected with differential bus protection, but the necessity and type of bus protection depends on factors including bus configuration, relay input sources, and importance of the equipment.

b. The bus between the generator breaker and GSU transformer is grounded through the neutral grounding of the generator, and ground detection is provided by the generator protective relay when the unit is connected. However, when the unit is not connected, the bus is ungrounded. Consider installing wye-wye VTs on the delta bus for ground detection when a generator is not connected.

c. Ground detection should be provided on any ungrounded or high-impedance grounded buses of the station service switchgear. A 480V ground detector usually provides only an alarm indication.

17–5. Transmission Line Protection

The basic principles of line relaying practices are discussed in IEEE C37.113. Relays and associated settings need to be well coordinated with the utility and are based on the carrier or communication equipment available. Line protection may include:

a. 21 – Distance.
b. 25 – Synchronism check.
c. 50 – Phase definite time overcurrent.
d. 50Q – Negative sequence overcurrent.
e. 51G – Ground overcurrent.
f. 64/51N – Ground/neutral overcurrent.
g. 79 – Automatic reclosing.
h. 85 – Communications schemes/tripping.
i. 87 – Differential.

j. Breaker failure.

k. Switch-on-to-fault tripping (SOFT).

17–6. Feeder Protection

Medium-voltage feeder circuits should be protected with relays having phase and ground overcurrent elements. The ground elements should be coordinated to prevent shutdown of a generator due to a grounded feeder.

17–7. Circuit Breaker Protection

a. Trip coil monitoring (TCM) should be included with medium- and high-voltage breakers to provide an alarm if the trip coil becomes disconnected or otherwise fails in an open circuit condition. TCM should be active only when the breaker is closed, and a time delay is required to allow the breaker to open during normal tripping without initiating a nuisance alarm. TCM may be applied within the protective relay or as a separate device.

b. A stored energy capacitive trip device should be considered for all medium and high-voltage breakers. For generator breakers, the breaker should automatically open in the event that there is a loss of the breaker trip circuit DC control power or complete loss of DC for the entire plant. If a generator breaker fails to open when excitation is removed and a unit is supposed to shut down, the spinning unit functions as a motor driven by the connection to the grid through the generator breaker. This can quickly cause severe overheating and damage to the winding and other generator components.

Chapter 18
Supervisory Control and Data Acquisition

18–1. General

a. The purpose of the SCADA system is to provide an interface for supervisory indications, alarms, and control of various plant control systems. A distributed control system (DCS) is an alternative to a SCADA system that can provide similar functionality for hydroelectric plants. Much of the discussion in this chapter is relevant to a DCS as well.

b. As plant control and alarm systems increasingly transition to digital interfaces, more and more systems have the potential to be tied into SCADA. Any digital systems tied into the SCADA system must be done intentionally and according to applicable standards and regulations. IEEE 1010 and IEEE 1249 are both examples of applicable standards to hydroelectric SCADA.

18–2. Programmable Controller

The basis of control for a SCADA system starts with the programmable controller and its associated input/output (I/O) modules. The controller and associated I/O act as the main interface between the SCADA system and the field devices. It is beneficial to push as much of the control processing to the lowest system level possible to reduce the number of devices needed to run any particular process. For that reason, much of the control logic for a plant SCADA is run in a programmable controller.

a. *Controller Hardware*. The most common type of controller used for modern SCADA systems is a PLC or its more feature-rich counterpart, a programmable automation controller (PAC). The terms PLC and PAC are frequently used interchangeably. RTUs were a predecessor to PLCs and PACs that functioned similarly, which is why the cabinet is often still called an “RTU cabinet” despite housing a PLC. UFGS 40 60 00 Process Control is a valuable source for PLC hardware and software specifications.

b. *Input/Output Hardware*. The PLC interfaces with the field devices through I/O modules. Most PLC vendors have numerous types of I/O modules for interfacing with the various field devices. UFGS 40 60 00 is a valuable reference for I/O hardware specifications as well as specifications for the field devices with which the PLC interfaces.

c. *On-Rack Input/Output*. Many PLCs have the capability to use “on-rack” I/O, which means that the I/O modules are connected to the controller through a physical backplane. The alternative to on-rack I/O is to use remote I/O racks, and most PLCs can interface with remote I/O by using industrial protocols such as Modbus, Ethernet/IP, DNP3.0, Profibus, or others. These industrial protocols allow standard interfaces so that different vendors of PLC and I/O equipment can interact. PLCs that have on-rack I/O functionality can also communicate with remote I/O racks as needed.

d. *Controller Software*. The most common programming languages for PLCs are specified in IEC 61131-3. Most PLC vendors use proprietary software to program and configure the PLCs that they offer. This pairing of proprietary hardware and software comes with significant up-front costs. There are a few open-source PLC options available, but they have not received widespread adoption and may have a less intuitive interface or fewer features. Therefore, the up-front cost of using a PLC platform based on a proprietary hardware and software pairing for the PLC can result in reduced maintenance and associated training costs.

e. *Programming Tools*. There are also programming tools that provide a standard software platform for programming IEC 61131-3 languages on various hardware platforms. These tools have more widespread adoption than open-source PLC efforts, but the proprietary vendors are still much more commonly used in the U.S. power generation industry.

f. *Factors to Consider*. It is important to evaluate the up-front versus maintenance costs when selecting a PLC vendor and associated programming software. Other factors to consider include, but are not limited to, product innovation, enhancements, features, longevity of the vendor, product support/development from other third-party vendors, reliability, availability of parts, experience and industries served, migration paths forward, testing/standard/safety certifications, environmental ratings, familiarity of local USACE staff, ease of access for engineering data and product support (knowledge base, manuals, firmware, software upgrades, self-help, etc.), and live support (phone, chat, email).

18–3. Core Supervisory Control and Data Acquisition Database(s)

The core functionality for the SCADA system resides in the SCADA database. Generally, the supervisory alarm, indication and control points, sometimes referred to as tags, reside in the SCADA database. Modern PLCs have the capability for some alarm management, and if the SCADA is interacting with a PLC that is performing alarm management roles, the interaction between the two alarm management systems must be accounted for in design and implementation. In most cases, the SCADA database acts as the intermediary between the PLCs, HMIs, and any other databases. The SCADA database can be distributed across multiple nodes and geographical regions as needed by the individual project. This database is generally a real-time operational database, as opposed to a database used for storing information for later interaction.

a. *Core Database Hardware*. Traditionally, the core SCADA database resides on a server or multiple servers. This could be a typical server used for information technology (IT) applications or an industrial server/computer. Due to the widespread impact the SCADA database has on a plant, it is important to implement some redundancy or distribute the database across multiple nodes throughout the plant. At minimum, a cold spare should be configured so that field staff can quickly swap out hardware in the event of hardware or software failure.

b. *Core Database Software*. Numerous vendors offer SCADA database software. Similar to PLCs, open-source software for SCADA systems has not received widespread adoption. However, most SCADA software is hardware agnostic, similar to most IT software.

c. *Software Compatibility*. As the database often acts as an intermediary between PLCs, HMIs, and various other system databases, it is imperative that the software support the protocols, languages, and interfaces needed to fulfil the requirements of the plant. For example, a plant may need to upgrade the SCADA system, but there may be a desire to leave the existing PLCs to reduce costs. The designer should compare the protocols of the existing PLCs against the protocol drivers supported by any SCADA software being evaluated.

18–4. Distributed Control System

In a DCS system, the PLC and SCADA database functions are often combined into a single device. These devices are distributed throughout the plant as needed, thus reducing the impact of hardware failure.

18–5. Human Machine Interface

The HMI provides the graphical interface for the operator or other field staff to the SCADA system. It is imperative that the HMI be designed in a way that allows the operator to perform their duties as efficiently as possible. The HMI designer should consider ANSI/ISA-101.01 while designing the HMI layout.

a. *Human Machine Interface Hardware*.

(1) Modern SCADA systems can work on numerous hardware platforms (phones, tablets, laptops, desktop computers, etc.). The most common hardware type for SCADA HMIs at USACE hydroelectric plants is the desktop computer. Desktop computers offer flexibility in number and sizes of monitors. For example, it is common to see a desktop connected to an array of screens to allow an operator to view multiple screens at once. Also, many controls rooms have computers connected to large screens that can be seen throughout the control room.

(2) Industrial touch screen panels are also commonly used as SCADA HMIs on the plant floor.

(3) Laptops can be used as well but are ideal for technicians troubleshooting a system rather than an operator interface.

(4) Tablets and phones are not currently recommended due to cybersecurity concerns.

(5) One way to reduce hardware costs of the HMI is to use thin or zero clients as the HMI hardware.

(6) Lastly, for smaller SCADA systems within a plant, it can be effective to combine the core database software and HMI software on a single piece of hardware to reduce costs.

b. *Human Machine Interface Software*. SCADA vendors generally provide HMI software to go along with the database offerings. It is generally recommended to use this software for the HMIs in a SCADA system to facilitate seamless integration and to leverage testing done by the SCADA vendor. Most SCADA HMI software supports multiple programming languages for screen development (Python, Visual Basic, etc.); any need for certain programming languages should be considered when choosing an HMI software. Each HMI software package includes various features for alarm indication, response, and filtering that should be considered when evaluating an HMI software package.

18–6. Historian and Logging

A separate database is commonly used for historical data and log archiving. Many of the SCADA vendors also offer historian products to integrate with the core SCADA database. It can be beneficial to use the same vendor for the historian product as the core SCADA to leverage vendor testing. However, vendors usually test the core SCADA databases to work using common database interfaces that allow mixing and matching the historian products if desired.

a. *Historical data*. Historical data from the hydroelectric plants is becoming increasingly in demand every day due to a focus on data analytics. It is important to make sure that the correct points are being included in the historian to aid in these data analytics efforts. Flow, power, plant head, and starts/stops are just a few examples of data that has been requested from sites regularly. The system logging often has similar hardware requirements to the historian, so it can be implemented on the same node/nodes.

b. *Historian Hardware*. The historian hardware requirements are fairly similar to the core SCADA database requirements. This could be a typical server used for IT applications or an industrial server. A notable exception is that there is less need for redundancy because the historian is not required to be immediately operational to run the plant. In addition, as the historian is responsible for collecting and storing large amounts of data for long periods of time, the historian nodes need more data storage capacity. This need for ample storage capacity is one of the reasons that the system log archiving node is often combined with the historian node.

c. *Historian Software*. It is important to consider the ability to interact with other databases when evaluating a historian product. As the focus on data analytics and remote troubleshooting has increased, the need to get regular historical data, and even logs out of the historian to another node, for further analysis drives the need to have a historian product that has numerous interfaces. For system logging, Syslog has become a common format.

18–7. Operating Systems

a. The various SCADA system components can lend themselves to a mixture of operating systems. It is possible to have a tailored proprietary operating system for the SCADA system components. However, it is more common to use typical IT operating systems especially for the components above the controller. It is common for controllers to use a tailored proprietary real-time base operating system, but some vendors offer controllers built on open-source operating systems. Most core database, HMI, and historian software are designed to run on multiple operating systems.

b. One way to reduce impacts of hardware upgrades and increase recovery options is to virtualize various nodes of the SCADA system. This is less likely to be implemented for controller nodes than other nodes on the SCADA system. The higher level nodes such as the core database or historian are more likely to benefit from virtualizing the underlying operating system. Virtualization can add some troubleshooting and overall complexity due to the abstraction from the base hardware. Therefore, the benefits of virtualization need to be compared to the drawback of this added complexity during design.

18–8. Hardware Environmental Considerations

a. The environmental conditions vary considerably from plant to plant and even within a plant. For example, the conditions a controller in a stand-alone RTU cabinet in a switchyard experience are significantly different than the conditions for an HMI in a control room. The switchyard RTU may experience high temperatures and high humidity in the summertime. Conversely, there are usually environmental controls for a control room already in place.

b. It is important to consider these environmental considerations and compare them to the specifications of the hardware to reduce the likelihood of failures. One way to address this is to specify industrially hardened components rated for wide temperature ratings, vibrations, dust, and/or humidity. Another option is to add environmental control systems (such as air and humidity controls) where there is SCADA hardware. Redundancy in any environmental control systems should also be considered to improve reliability. If components can be used that do not require environmental controls, then it reduces one area of possible failure in the system.

18–9. Automatic Generation Control

a. *Overview*. Many USACE plants are equipped with AGC functionality in their SCADA systems, especially if the plant has numerous units. The AGC system uses algorithms to take a generation request in megawatts from the PMA, and it may automatically distribute the load among the units or make a recommendation to the operator. Unit ramping considerations can also be considered within AGC functions. The various power marketing authorities that interact with USACE have varied requirements for ramping and data reporting, so coordinating with the applicable PMA is crucial.

b. *Ramping Considerations*. To reduce any errors in power generation, it is ideal to have a unit ramp linearly up and down when the PMA requests changes. However, each family of hydroelectric turbines and generators have unique operational rough zones. Avoiding these rough zones reduces wear and tear on the unit. Therefore, the desire to have a consistent and orderly ramp can compete with the desire to avoid the rough zone especially when units are starting and stopping. Coordination with the PMA on how to best address ramping through rough zones helps to reduce errors in forecasted generation.

c. *Frequency Response*. The AGC functionality in a plant has the potential to counteract the response of the governor to a grid frequency event. Counteracting the response of the governor to a grid disturbance is highly undesirable because it can invalidate grid response models and possibly aggravate the grid disturbance. Therefore, it is important to verify that the SCADA system does not operate in a way that counteracts a governor response to grid disturbances.

18–10. Automatic Voltage Control

Automatic voltage control (AVC) functionality is in some ways similar to AGC, except that it is used for voltage and reactive power as opposed to real power and frequency. The interaction between AGC and AVC can be vital at some plants that are critical to grid stability. However, for most plants, voltage control functionality is less critical. The importance of AVC may increase at more plants if power marketing agencies are in the future able to market the flexibility that hydroelectric plants provide in voltage and reactive power support.

18–11. Remote Operations

a. ER 1110-2-1156 should be consulted for any design decisions made regarding remote operations of plants. It lists dam safety requirements for remotely operating USACE dams and associated water control systems. Numerous USACE plants are currently remotely operated. The number of plants remotely operated has been increasing as communication infrastructures and technology have advanced. There are also other important items to consider when expanding remote operations.

b. The Hydroelectric Design Center has a list of recommended indication, control, and alarm points to utilize when implementing remote operations at a plant. This list of points is constantly being refined through iterative design, review, and collaboration with operations staff. This list also includes some recommended safety controls to implement.

c. The expansion of digital systems has caused more and more data to be placed into the SCADA system. When this is paired with expanding remote operations and consolidated control centers, the capacity of operators/ dispatchers to react to this data needs to be considered.

d. The alarms should be categorized and rationalized so that operators/ dispatchers receive a high-level overview of regional plant alarms on one screen without being overwhelmed. Further detail can be included on more specific plant or subsystem alarm screens as desired by the operations staff. The specific plant/subsystem alarms should be recorded for maintenance staff to assist them in restoring equipment efficiently.

18–12. Unit Automation

Consult ER 1110-2-1156 for any design decisions regarding automation of units at hydroelectric plants. While the start and stop sequence has been automated for USACE units, the automatic starting and stopping of units based on requests from the AGC system has not yet been widely adopted.

18–13. Procurement

a. SCADA integrators/hardware installers and hardware/software suppliers are often separate entities. Therefore, it is possible to have separate specifications for hardware/software and integration/installation efforts. It is also possible to procure hardware/software under a separate contract and provide the hardware/software to an integrator/installer as Government-furnished equipment.

b. There are a few reasons that a sole source procurement of hardware or software may be necessary for a SCADA system. One is the need to use Department of Defense (DoD)-approved hardware or software. Another reason may be the need to standardize equipment across region, district, or plant for maintenance reasons. This is typically addressed on a project-by-project basis.

18–14. Acceptance Testing

a. Factory acceptance testing (FAT) should be performed for any new RTU or control cabinets supplied. A Government representative should be present for at least the first factory acceptance test for RTU cabinets associated with a given project.

b. Site acceptance testing (SAT) should be performed by both the RTU installation contractor and the SCADA integrator. Sometimes the SCADA integrator and RTU installation contractor are the same entity.

c. UFGS 40 60 00 is a valuable source for FAT and SAT specifications. HDC maintains a version of UFGS 40 60 00 tailored for hydropower purposes.

18–15. Training

a. The SCADA integrator should provide operator training and maintenance training. The length of this training varies depending on the functionality and complexity of the SCADA system. Training and associated manuals are also covered in UFGS 40 60 00.

b. At minimum, a maintenance manual and an operator manual should be provided by the SCADA integrator. The maintenance manual should address recommended recurring maintenance tasks for the SCADA system.

18–16. Maintenance and Upgrades

a. Due to the interoperability of the SCADA system, individual components can often be upgraded incrementally without needing to do a wholesale replacement. This can be useful when upgrading HMI or higher level functionality because new SCADA software can often interface with legacy PLC systems. The process for piecemeal replacements can be different for a DCS system due to the close coupling between HMI, database, and controller functions.

b. Most SCADA and controller vendors provide software and firmware updates. These updates need to be applied regularly because they often contain bug fixes or cybersecurity improvements.

18–17. Cybersecurity for the Hydroelectric Power Plant Control System

Design of the hydroelectric control system and the cybersecurity of the system should be done in parallel.

a. *Centers of Expertise*. USACE has two centers of expertise (CX) for cybersecurity. Both provide guidance on implementing DoDI 8510.01 regarding the risk management framework (RMF) for DoD IT. The goal of RMF is to evaluate and mitigate the risks of a system so it can be authorized to operate.

(1) The Control System Cybersecurity Mandatory Center of Expertise (CSC-MCX), located in Huntsville, Alabama, focuses on facility-related control systems, such as electronic security systems for physical security.

(2) The USACE Critical Infrastructure Cybersecurity Mandatory Center of Expertise (UCIC-MCX), located in Branson, Missouri, focuses on civil works. The assessment of hydroelectric control systems cybersecurity falls under the purview of the UCIC-MCX.

b. *Risk Management Framework*. There are seven steps in the DoDI 8510.01 RMF process. Designers must follow the RMF steps that are outlined below and coordinate with the UCIC-MCX. The system owner, designer, or contractor must ensure that the security controls are implemented, assessed appropriately depending on external connectivity, and that the system is monitored throughout its life cycle.

(1) RMF step 1 is to identify the capable personnel who will execute the RMF. The system owner performs this step.

(2) RMF step 2 is to categorize the system. This has been performed by the UCIC-MCX. The four main architecture types for operational technology (OT) systems are:

(3) *Operational Technology Product*. An OT product is a small industrial control system (ICS) consisting of a single PLC and an operator interface. The operator interface uses an embedded operating system, but only serial communications are used.

(a) *Operational Technology Subsystem*. The OT subsystem is composed of one or more PLCs and a computer-based HMI. Devices are interconnected using an Ethernet network, a routable protocol. The system cannot provide remote access and it cannot include a routable connection to any external networks (outside the physical boundary).

(b) *Operational Technology System Closed Restricted*. An OT closed restricted system is a subsystem that is networked to another Government-owned system within an identified boundary under the control of a single authority and security policy. The systems may be structured by physical proximity or by function, independent of location. A system is using encrypted virtual private network tunnels between sites to another Government-owned or operated subsystem. The system cannot include any routable connections outside the authorization boundary.

(c) *Operational Technology System Restricted Interconnected*. An OT restricted interconnected system, formerly known as a Platform IT (PIT) system restricted interconnected, is an OT system or subsystem that has interconnection capabilities with any external network. This interconnection is typically used for the transfer of data from one system to another Government-owned, Government-operated control system.

(4) RMF step 3 is to select the security controls. This has been performed by the UCIC-MCX. The National Institute of Standards and Technology (NIST) 800-53 Revision 4 security control baselines for hydropower and auxiliary hydropower systems are as follows for Confidentiality (C), Integrity (I), and Availability (A): hydropower is Low, Moderate, Moderate (LMM), and auxiliary hydropower is Low, Low, Low (LLL).

(5) RMF step 4 is to implement the security controls. The system owner performs this step.

(6) RMF step 5 is to assess the security controls. This is performed by either the UCIC-MCX or by a third-party Army assessor. There are three assessment types: Assess Only, Assess and Authorize Organization, and Assess and Authorize Army.

(a) Assess Only is for OT products. The assessment is performed by UCIC-MCX.

(b) Assess and Authorize Organization is for the OT subsystem and OT system closed restricted types. The assessment is performed by UCIC-MCX, as the organization.

(c) Assess and Authorize Army is for the OT system restricted interconnected type. A third-party authorized assessor performs the assessment.

(7) RMF step 6 is to authorize the system. This is performed by the authorizing official, which is the USACE CIO/G-6 Chief Information Officer.

(8) RMF step 7 is to monitor the security controls. The system owner performs this step.

Chapter 19
Penstock Shutoff Valves at the Powerhouse

19–1. General

USACE projects use large diameter butterfly valves in the powerhouse end of a penstock when additional shutoff capability and/or unit isolation capability is required for a main unit during emergency or maintenance activities. Large diameter spherical valves are also an acceptable and viable type of valve that could also be used in this manner. However, currently USACE has generally elected to use large butterfly valves for the applications of this chapter. Consideration and criteria are provided for both large diameter butterfly and spherical valves in this chapter.

a. General considerations when developing the design for new valves includes:

(1) Determining need and system performance requirements.

(2) Selecting type, size, and materials.

(3) Selecting auxiliary equipment including safety features.

(4) Coordinating location and space requirements.

(5) Access considerations for actions such as installation, inspection, operation, maintenance, and future removal and replacement of components including entire valve assembly and valve operator.

(6) Necessary load handling for installation and future O&M actions with the assembly verses the facility's capabilities, both temporary during construction and permanent, such as rating(s) and range(s) of crane(s) and lifting points.

(7) Ability of new valve design and installation to allow future refurbishment and replacement.

(8) Translating design requirements for proper incorporation into acquisition documents such as contract drawings and specifications.

(9) Confirming that contractor submittals provide appropriate opportunities to verify that both the overall design approach and unique details satisfy site-specific Government requirements.

(10) Witnessing key manufacturing, field assembly, and test events.

(11) Integrating contractor-supplied O&M manuals into powerhouse-specific O&M manuals.

b. General considerations when developing the design for refurbishing these valves includes:

(1) Assessing current equipment condition and suitability for refurbishment.

(2) Current system performance needs.

(3) Assessment and potential upgrade of auxiliary, controls, and monitoring equipment, including addition of safety features.

(4) Existing access for necessary actions such as removal and replacement of components.

(5) Necessary load handling for refurbishment versus existing facility capabilities such as crane rating and range and lifting points.

(6) Ability of existing design to allow necessary refurbishment.

(7) Potential improvement of access and addressing of space limitations.

(8) Translating refurbishment requirements for proper incorporation into acquisition documents such as contract drawings and specifications.

(9) Confirming that contractor submittals provide appropriate opportunities to verify that both the overall design approach and unique details satisfy site-specific Government requirements.

(10) Witnessing key manufacturing and field assembly and test events.

(11) Integrating contractor-supplied O&M manuals into powerhouse specific O&M manuals.

19–2. Valve Requirement

For a new powerhouse or a major redesign of an existing intake arrangement, a shutoff valve may be required at the powerhouse end of penstocks for either turbine or pump-turbine units. Several factors should be considered when determining the need for a shutoff valve at the unit. The factors include the following:

a. Purpose. The purposes of a unit-adjacent valve are to provide emergency shutoff in case of flooding-type failure or loss of speed control, to reduce leakage through wicket gates, and to unwater the turbine for maintenance. However, secondary shutoff provisions such as gates are usually required at the intake of each penstock (the primary means of shutoff is governor actuation of the wicket gates). As a result, a shutoff valve at the unit may not be required.

b. Type of Shutoff at the Penstock Intake. A quick-closing shutoff at the penstock intake, operable under emergency conditions, may be an alternative to a shutoff at the powerhouse. Typically, maintenance and emergency shutdown can be satisfied with an intake shutoff valve, making the need for additional valves at the powerhouse no longer technically or economically justified.

c. Length of Penstock. A long section of penstock downstream of the shutoff at the intake increases the time required to shut down the unit during an emergency closure, increase the time required to unwater the unit, and increase leakage losses. Maintenance and emergency shutdown requirements usually justify a powerhouse shutoff when the penstock is several hundred feet long.

d. Head. A shutoff valve near the turbine or pump-turbine unit reduces the effective head on the unit, which, in turn, reduces the leakage.

e. Multiple Units per Penstock. Common station layouts, especially those with a temperature control structure intake, have a bifurcation or trifurcation (see Figure 19–1), in which a single intake splits to feed into multiple units. If the closure is made at the single intake to perform maintenance or operation action on a single unit, then all units would require shutdown. To avoid this impact, the layout used for operational and maintenance flexibility normally requires a separate shutoff valve for each unit. Generally, maintenance requirements alone justify powerhouse shutoff valves for multiple unit penstocks.

f. Type of Wicket Gate Seal. A tight seal reduces leakage losses. However, deterioration of the seal with time should be considered when determining the effects of leakage. Evaluation of the factors should consider their effects on maintenance, emergency operations, and costs. The factors considered and basis of determination should be included in the design memorandum. Including the additional shut-off valve could be a layered approach to address potential impact of wicket gate seal performance degradation.

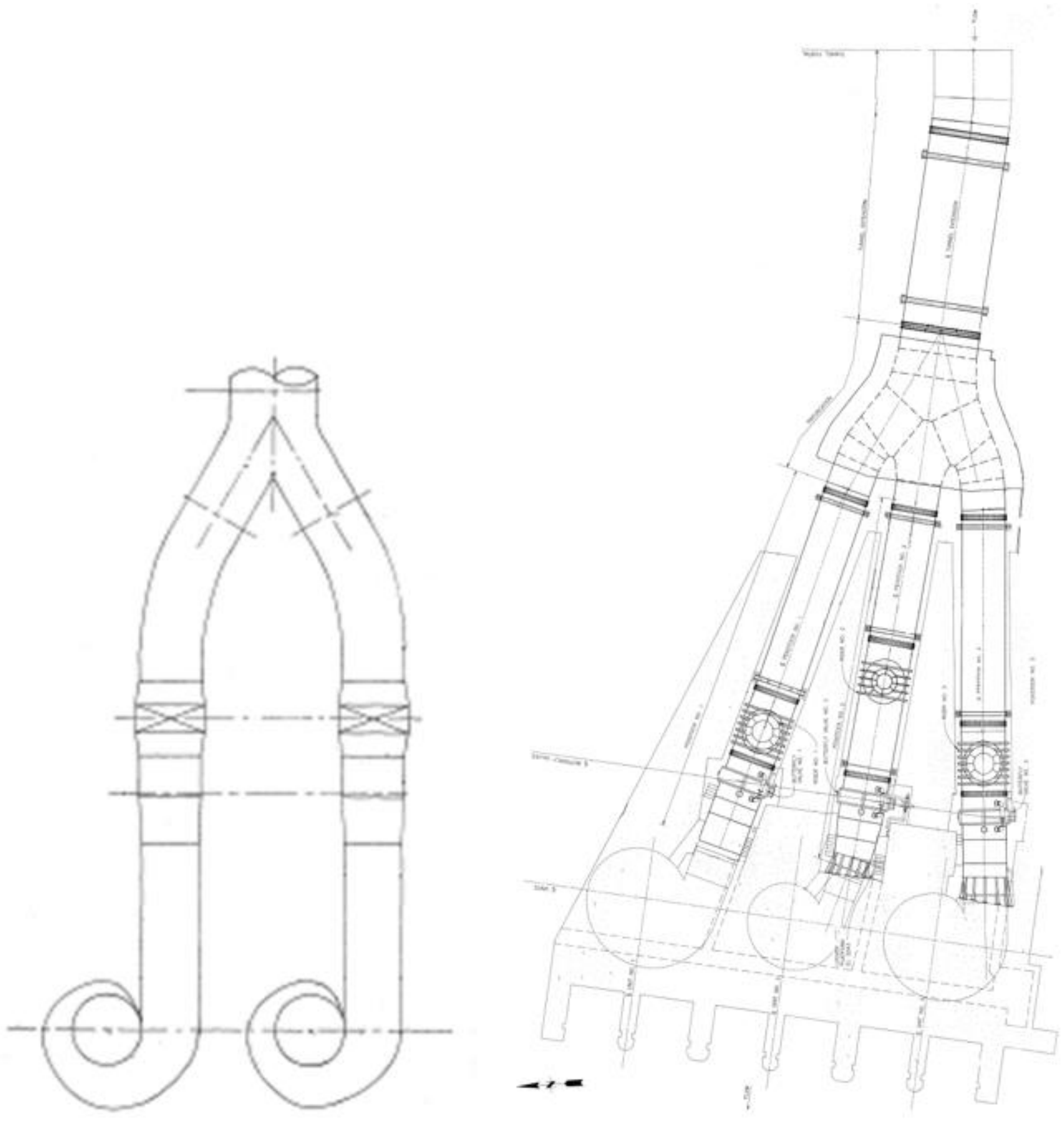


Figure 19–1. Penstock bifurcation (left) and trifurcation (right)

19–3. Penstock Shutoff Valve Selection

Butterfly and spherical valves are generally available as a catalog item for heads up to 600 ft (183 m) and in sizes up to 8 ft (2.4 m). Valves for conditions exceeding these limits are typically designed and manufactured for the specific application with some companies having “families” of valve designs that are adjusted to meet the necessary parameters. Due to additional operational and risk reduction features required and recommended for USACE application, most unit valves should be custom designed based on existing production valves. Factors to be considered include initial cost, maintenance cost and complexity, head loss through valve, and requirements for transition sections.

a. Butterfly Valves. Butterfly valves consist of a valve body, valve disk, bearings, and operator. Head loss through a butterfly valve is higher than for a spherical valve. Head loss may justify an oversize valve with suitable transition sections, but these require additional exposed space to accommodate. Some internal bypass leakage is characteristic of the metal-seated butterfly valves. Currently most existing USACE powerhouses use butterfly valves for their penstock shutoff valves. See Figure 19–2 for an example of a butterfly valve mid-install.

Figure 19–2. Flanged horizontal butterfly valve with hydraulic operator and lenticular disk (shown unlinked) with scroll case extension removed

b. Spherical Valves. Spherical valves consist of a valve body, valve rotor (ball), bearings, and operator. In the fully open position, the rotor has a full diameter water passage axially aligned with the penstock. The bore size can be set to match that of the passageway so that no portion of the valve assembly is in the flow path. Head loss through the valve in the full-open position is approximately the same as an equal length of penstock. When rotor is rotated 90 degrees to the fully closed position, the valve presents a solid surface, closing the water passage. See Figure 19–3 for the basic spherical valve cross section.

(1) Movable seal rings permit tight shutoff. Wear of the sealing surfaces is minimized because the wear rings are not in contact with the mating surfaces until after valve rotation is complete.

(2) To accommodate the valve rotor, the valve body is generally longer and heavier than that of a comparable butterfly valve, with additional structural support necessary for the assembly. Fabrication and machining costs, as well as installation provision costs, are relatively high when compared with a near functional equivalent butterfly valve.

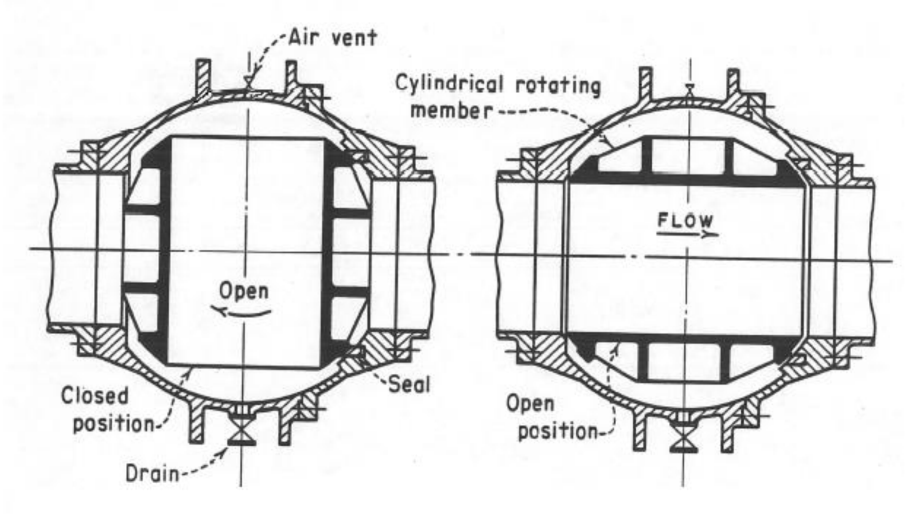


Figure 19–3. Basic spherical valve cross section in closed and open positions

19–4. Butterfly Valve Detail Requirements

a. Industry Standards. Butterfly valves for USACE facilities should be acquired in coordination with applicable industry standards. For elastomeric-to-metal disk seal systems, the latest version of American Water Works Association (AWWA) C504, AWWA C516 should be used. Metal-to-metal disk seal systems do not have an applicable industry standard with which to coordinate acquisition. See Figure 19–4 for general arrangement of a butterfly valve.

b. Valve Body. The valve body should be of either cast or fabricated construction and include connecting flanges rated at or above that of the penstock. Design and fabrication should be consistent with section VIII of the ASME BPVC. The valve body design addresses the hoop forces from the internal pressurizing, the thrust forces from the water flow through it, and the structural forces in reacting the load from the valve disk or rotor and its operator throughout its full range of motion.

c. Disk.

(1) The valve disk should be of cast or fabricated construction and either lenticular or open truss (flow-through) design (see Figure 19–5). Losses have been found to be somewhat higher for lenticular-type disks versus the open truss-type disk because the lenticular style causes a greater reduction in cross-sectional area. Lenticular disks, however, have the advantage of a smoother interface with the flow profile creating less turbulence, and therefore, lower forces and less fatigue on the disc itself.

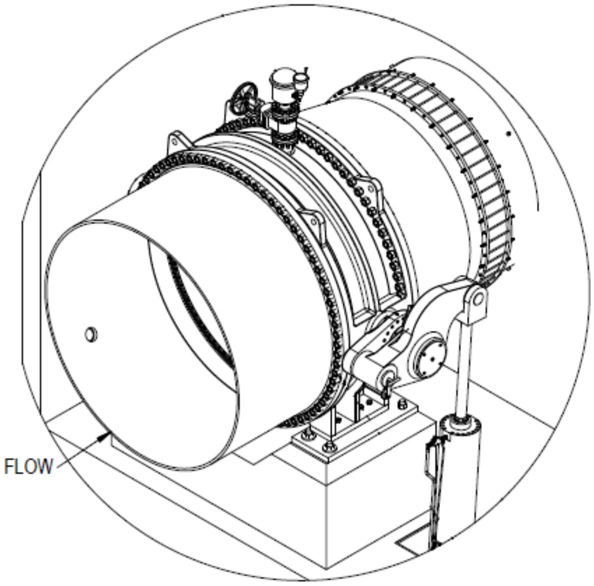


Figure 19–4. Isometric view of a flanged horizontal butterfly valve with exposed linkage hydraulic operator and scroll case extension slip-joint (right)

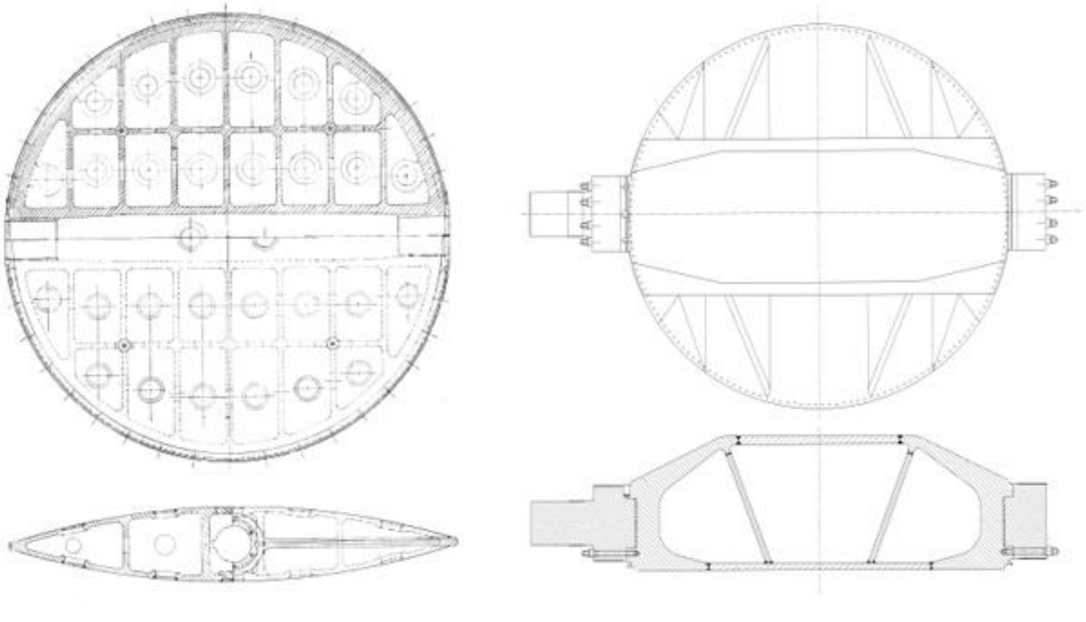


Figure 19–5. Lenticular disk, zero offset with cross sections (left) and open truss (flow-through) disk, single offset, with cross section (right)

(2) At design head, stresses should not exceed 50 percent of the material yield point or 25 percent of ultimate material strength.

(3) Fabricated designs should be stress relieved before machining.

(4) Disk design should provide for wedge sealing action with the disk at less than 90 degrees to valve axis, and the disk should have positive overtravel limits. The limit may be provided by mechanical stops or by bottoming of operator piston.

d. Design Requirements per Hydraulic Steel Structures. Due to the use of these valves for maintenance, in which personnel are working behind the unit valve with the penstock watered, these valves are to comply with the applicable HSS guidance of USACE in which calculated stresses do not exceed the allowable stresses from EM 1110-2-2107. Compliance must be incorporated into the design of new valves and assessed for a major refurbishment of existing valves. For both new and major refurbished valves, the assembly design must be assessed to determine the fracture-critical members and the adequacy of their design for the operating conditions. The valve industry is not familiar with USACE HSS requirements, so they will need to be translated into common stress and evaluation requirements.

(1) For new valves, the design calculations of the fracture-critical members must show proper design for the operating conditions, and each requires 100 percent factory inspection and documentation. The documentation of these inspections is to be incorporated in the valve O&M manual for future reference. Unit valve design must be such that the start of a structural failure will be first exhibited an internal bypass leakage of the valve and not a cascading failure that will result in immediate excessive external loss of water or internal bypass.

(2) For major refurbishment of a valve, the assembly requires determination and inspection of the facture-critical members for manufacturing defects and metal degradation. The existing conditions and design of the facture-critical members should be collectively assessed for adequacy. It is common that the complexities and risks associated with the assessment of these members existing conditions result in valve replacement.

(3) Due to the “flow-through” aspect of an open truss design, more members of this type of disk are subjected to tension, increasing the number of fracture-critical regions of the assembly. The open truss design does allow direct access to most, if not all, of these locations for non-destructive examination (NDE). A lenticular disk has fewer regions of the assembly in tension, but due to a closed design, is more complex for assessment through NDE.

e. Seals. Valve body and disk seals should be either a metal-to-metal, or metal-to-elastomeric seal system. Suitability of the seal system components, of either type, for resistance to corrosion and degradation in the penstock water should be verified by prior operating experience or chemical analysis.

(1) *Metal-to-Metal Seal System*.

(a) A metal-to-metal seal system can have a 30- to 50-year design life, but will present bypass leakage of up to 20 gallons per minute (gpm) (75.7 lpm) when newly installed.

(b) The disk seal should be made of corrosion-resistant steel with the valve body seal of a different composition and lower hardness, such as bronze or brass, to minimize potential for galling. The hardness of the disk seal should be the higher of the

pair of seals due to the disk seal location in the flow path resulting in being subjected to the highest flow velocities and higher likelihood of direct impact from debris.

(c) Both seals should be replaceable without dismantling the valve, and the body seal should be adjustable from outside the valve. Seal system design should not be compromised to allow a manufacturer's standard design.

(2) *Metal-to-Elastomeric Seal System*.

(a) Metal-to-Elastomeric Seal. A metal-to-elastomeric seal can provide zero bypass leakage at first installation, but may require the elastomeric seal to be replaced in the 20-year time frame. The seal system must be a proven design for water velocities exceeding those of the proposed application.

1. The metal seal or seat should be of corrosion-resistant steel.
2. The elastomeric seal system should be replaceable without dismantling the valve, and adjustable with the valve in the closed position.
3. Location of the disk seal should be such to limit potential damage from debris passing through the valve.

(b) Location of Metal Seal and Elastomeric Seal in New Valves. In new offset shaft (single, double, or triple) valves the elastomeric seal should be placed in the disk because in this configuration, the seal can be continuous, reducing the challenge of addressing the potential bypass leak path at end interfaces with the trunnion. In addition, the elastomeric seal system may be subjected to less scouring forces when placed in the disk over that of the valve body. For new concentric or zero-offset valves, the trunnions, or shafts, of the disk prevent a continuous seal for both the body and disk seals. It is still recommended to pursue an elastomeric seal in the disk, but the design testing and fielded history of the valve supplier's design should also be considered. Overall, a higher level of performance success has been found with having the seal in the disk, especially for single-, double-, or triple-offset valves.

(c) Location of Metal Seal and Elastomeric Seal in Refurbished Valves. If converting an existing metal-to-metal seal valve to a metal-to-elastomeric seal valve, the new elastomeric seal is usually placed in the location of the metal seal that had adjustable seal segments when performing the conversion. The original fix metal seal remains the fixed metal seal. The testing and fielded history of both the design and installation for a seal conversion must be evaluated. The new seal system designer must review, approve, and oversee the physical process of conversion to confirm that the design and installation are equivalent.

(d) Location of Metal-To-Metal Seals in Refurbished Valves. If refurbishing a metal-to-metal valve seal system with a metal-to-metal seal system, the original seal design should be followed; except when considering different seal metals if the original design does not address the design considerations detailed in this document for such seal systems.

(3) *Replaceable Metal Body Seal or Disk Seal*. Even though cycling wear is not a concern, erosion due to flow needs to be considered. High silt conditions can lead to scouring of metal sealing surfaces that may need to be addressed. Having a replaceable surface allows for future replacement. It is not always common design to have this surface replaceable, so coordination with industry is recommended to confirm such a feature is available for the size and function of valve being procured.

(4) *Internal Leakage*. Sealing from internal leakage at the shaft and trunnion interface presents challenges. An offset-valve disk (single, double, or triple) avoids the need for a secondary seal system for the trunnion. If an elastomeric trunnion seal is used, then provisions must be provided that allows inspection and replacement without full assembly of the valve. If spring loaded metal seals are used, they must be sized and installed in a manner that does not allow spring fatigue, and provisions must be provided that allows inspection and rework without full assembly of the valve.

(5) *Seal Design*. The seal system is to be designed for its operating conditions, including opening. The system must be designed to operate under the pressure differential across its closure component (disk or rotary ball) that will occur when the valve is opened from the closed position without impact to any component's operational life. Including a bypass system that allows filling the downstream side of the closure component to reduce the pressure differential is recommended to assist in the reduction of forces, in addition to reducing the impact of opening the valve to downstream components. Even with the bypass system, the designer should consider not accounting for the reduction in pressure differential at opening when setting requirements for the valve assembly, to provide a more robust design.

f. *Valve Disk Orientation*. A butterfly valve can have a vertical or horizontal orientation of the disk. The orientation establishes the location of the valve operator interface with the valve disk's shaft and loading of the valve shaft bearings. Access and spatial limitations influence which orientation is used.

(1) *Horizontal Disk*.

(a) Horizontal disk orientation is where the centerline of the disk rotation is horizontal to the flow conduit, as shown in Figure 19–2. This is the recommended orientation for USACE butterfly valves if it can be accommodated spatially.

(b) The horizontal orientation simplifies the support of the valve disk throughout its range of motion and works with gravity. The weight of the valve disk assembly is divided between the two trunnion bearing assemblies on each side of the valve where the shaft transitions through the body. These two areas are also located over the valve body supports, which translates most of this loading directly through the valve body to the external valve body supports anchored to the floor.

(c) With this orientation, most of the forces from the assembly into the valve body are compression loads, as opposed to torsional or moment loading. It is less complex to design the valve body against distortion for this type of loading. Preventing flexing or distortion of the valve body retains an even internal sealing surface, which greatly reduces the potential for increased internal leakage over the life of the valve.

(d) This orientation presents benefits when performing inspections or work on the disk. The full disk seal and the valve's internal trunnion interfaces can be inspected in the open position without ladders or scaffolding that can be difficult to deploy inside the valve. For work requiring support of the disk, it allows support from the ground level that is distributed on each side of the valve. The trunnion seals and bushings should be designed for inspection and replacement for the outside of the valve, without having to remove or modify the disk and shaft assembly.

(e) The valve operator interface with the disk is halfway up the valve. For large diameter valves, this location can present access complexities to the trunnions and valve operator-to-disk shaft interface and require longer valve operators. Either

permanent means to access this area must be provided, or the arrangement must allow deploying a temporary means without disassembly of any equipment. Permanent access provision for this area should be installed that does not require deploying any temporary fall protection measures.

(2) *Vertical Disk*.

(a) Vertical disk orientation is where the centerline of the disk rotation is vertical to the flow conduit. Figure 19–6 shows an example of this arrangement.

(b) Vertical orientation of the butterfly valve disk allows the valve operator interface to be located on top of the valve, which can reduce spatial complexities and length of the valve operator.

(c) There are three disk bearing assemblies, as opposed to the horizontally orientated disk's two assemblies. The upper half of the disk has the upper trunnion bearing assembly. The lower half has two bearing assemblies, the lower trunnion bearing assembly and the thrust bearing assembly. The thrust bearing assembly reacts to the load of the disk assembly weight throughout the valve's range of motion. The lower trunnion bearing assembly balances the rotation of the disk shaft in coordination with the upper trunnion bearing.

(d) Access for all three bearing assemblies for service inspection, and removal must be accommodated.

(e) Unlike the horizontally orientated valve disk, the vertical orientation places the support of the disk assembly between the valve body support pedestals. The orientation transfers a portion of the disk assembly weight directly to the valve body as moment and torsional loading that varies throughout the range of motion of the valve disk, in addition to compressive loading. Design of the valve assembly to include these varying forces and prevent flexing or distortion of the valve body is more complex than that of a horizontal valve.

(f) Proper lower support of the valve disk assembly throughout its motion range is critical for the long-term disk seal system performance in preventing internal bypass leakage. When the valve is fully closed, the highest amount of dead load is reacted into the valve body. If not properly supported, the disk can shift in elevation due to either allowable play in the support design or valve body flexing. This shift reduces the coverage by the seal system for the upper trunnion area, which results in concentrated internal leakage at the top valve disk. The drift of the disk elevation may be noted immediately on install or may slowly increase over time.

g. Valve Shaft.

(1) The valve shaft for lenticular disks should be one piece or two sections connected to the disk with fitted bolts. Shafts for open truss-type disks may also be bolted on if using fitted bolts.

(2) Corrosion-resistant sleeves should be provided at the packing boxes if non-corrosion resistant shafts are used.

(3) The bearing shaft finish must be suitable for the functional life of the seal systems.

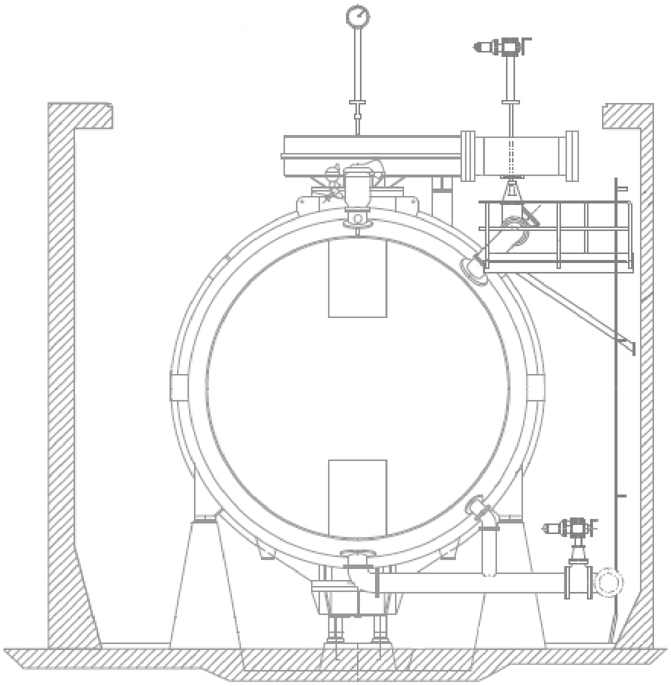


Figure 19–6. Vertical penstock butterfly valve with horizontally mounted hydraulic actuator and encased operator linkage (top)

h. *Bearings*.

(1) Bearings for disk shafts should be sleeve type and have housing that can be accessed and serviced without dismantling the valve.

(2) Bearings made from bronze or self-lubricating materials are acceptable. If bronze is used, a dedicated lubrication system must be provided.

(3) Vertical-oriented shafts require a thrust surface on the lower end. The surface should be adjustable for centering the disk in the valve body.

(4) Where possible, the bearing housings should allow external access for inspection and replacement without dismantling the valve. It is easier to implement this feature with a horizontal orientation of the operator shaft.

19–5. Spherical Valve Detail Requirements

a. *Arrangement*. A spherical valve arrangement is like that of a butterfly valve in the same application. Typically, the shaft is oriented horizontal (as shown in Figure 19–7) for similar reasons as the butterfly valve.

b. *Industry Standards*. Spherical valves for USACE facilities should be acquired in coordination with applicable industry standards.

c. *Valve Body*. The valve body should be two halves made of fabricated or cast steel, properly annealed. It must be adequately designed to resist the hydraulic forces acting directly on the body and those resulting from the thrust for any position of the valve rotor. Integrally cast or forged (if fabricated) steel flanges, suitably machined, should be provided for bolting the body pieces together, and circumferential flanges provided for bolting to the pipe extensions.

d. *Rotor*. The valve rotor (or rotary ball) should be made in one piece of annealed cast or fabricated steel and should adequately resist the bending and shearing load resulting from the hydraulic and operating forces.

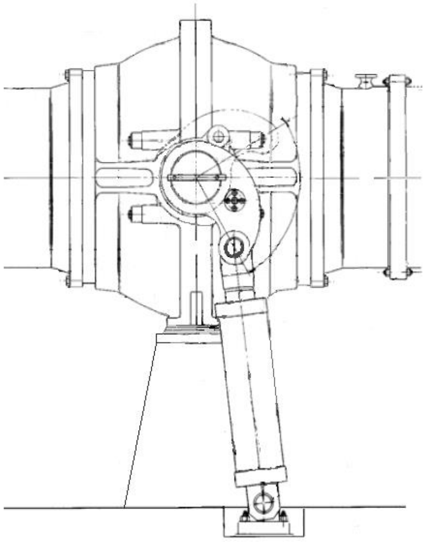


Figure 19–7. Horizontal spherical shut-off valve penstock butterfly valve, pedestal supported with vertically mounted hydraulic actuator

e. *Seals*.

(1) Retractable seal rings should be provided to permit separation of the sealing surfaces during rotation of the rotor. The retractable seal ring should normally be oil-hydraulically operated.

(2) Sealing surfaces should be corrosion resistant and of different composition and hardness to minimize galling. One seal of 300 series stainless and one of 400 series stainless will perform satisfactorily in most waters. The rotor’s seals should be 400 series stainless seal and of a higher hardness than the seals of the valve body. However, the source water should be checked for unusual corrosiveness that may cause an alternative approach with the materials should be specified accordingly.

(3) Both sealing surfaces should be removable for replacement. Both upstream and downstream seals may be justified to allow more flexibility in scheduling seal replacement.

f. *Trunnion Bearings*. Trunnion bearing with renewable self-lubricating bronze sleeves and bronze thrust washers should be provided. Bearing housings should be integral to the body casting. A means of adjusting and centering the rotor should be provided. Pressure relief for leakage water through the gland should be verified.

g. *Design Requirements per Hydraulic Steel Structures*. As with butterfly valves, spherical valves are used for maintenance, in which personnel are working behind the unit valve with the penstock watered. These valves must comply with the applicable HSS guidance of USACE in which calculated stresses do not exceed the allowable stresses from EM 1110-2-2107. Compliance must be incorporated into the design of new valves and assessed for a major refurbishment of existing valves. For both new and major refurbished valves, the assembly design must be assessed to determine the fracture-critical members and the adequacy of their design for the valve's operating conditions. The valve industry is not familiar with USACE HSS requirements, so they need to be translated into common stress and evaluation requirements.

19–6. Butterfly and Spherical Valve Common Requirements

Butterfly valves and spherical valves have common design requirements, safety provisions, and refurbishment details. The following are applicable to both types of unit valves.

a. Design Conditions.

(1) Valves should be designed for maximum penstock head, including the possible water hammer events. Because of the significance of a water hammer event on the design of the valve, it should be included in the conducted dynamic analysis of the penstock, from upper reservoir to the power generating unit. The results should be documented in the design process for the valve. In addition, since the valve may be used to test the penstock and/or spiral case, and during spiral case grouting, the design should also be adequate for these heads as applicable. The installation may require the valve to withstand heads from either direction when closed.

(2) If the valve is to be used for emergency closure, the operator should be capable of closing the valve in 2–5 minutes, as practicable for the size.

b. Design.

(1) Detailed design of valves and operators should be specified as a contractor responsibility. However, the valves are a critical item in obtaining and maintaining satisfactory unit operation. Therefore, the specifications should require equipment of a design proven in service. Standard catalog equipment is preferred when available.

(2) Where a size and head rating not previously used is required, the specifications should require the bidder to have experience in designing and manufacturing similar valves of the approximate size and head rating.

(3) All parts and components subject to loading from operation of the valve operator should be designed for maximum stress of 75 percent of yield point with maximum attainable force from the operator.

(a) For hydraulic operators, the maximum attainable force is that which is from the maximum attainable pressure in the cylinder. Maximum attainable pressure should be assumed as either pump shutoff pressure or maximum setting of the relief valve sized for maximum pump delivery, whichever is greater.

(b) For electric motor driven operators, the maximum attainable force is from the motor breakdown torque.

c. Bypass. A bypass valve permitting the establishment of equalized pressure internally on both sides of the shut-off valve's flow control component (disk or rotary ball) before opening should be provided. The pressure equalization provides a less dynamic operating condition for the shut-off valve assembly, including its flow control component's seal system, increasing the functional life of the assembly. The equalization also provides a less dynamic condition for those components downstream of the shut-off valve. The bypass is normally motor operated for automatic control.

(1) The bypass should have a motorized plug valve for the standard operation of the bypass function. If the valve control is integrated into an overall shut-off valve operation or otherwise controlled away from the motorized assembly, then both a local control of the bypass valve motorized operation and a manual means must be included at the bypass valve. The valve position should also be easily visible from the valve room floor or operating platform without using a climbing device or removing covers.

(2) A normally open, manual gate valve should be upstream from the motorized bypass valve in the bypass assembly. The manual valve must be a closure backup for the motorized valve, as well as a means to allow maintenance activities with the motorized valve, without needing to unwater upstream of the unit valve.

(3) The pressure across the unit valve should be provided by a pressure monitoring system to confirm the bypass system’s filling of the cavity between the unit valve and the wicket gates. If a fully automated means is used for the pressure monitoring system, then an additional system consisting of analog gauges must be included to provide the pressure level directly upstream and downstream of the unit valve. The additional system allows both setting and troubleshooting the electronic means of monitoring and relay.

d. Valve Operator. Hydraulic or electrically motorized means of operating the unit valve should be used. See Figure 19–8 for an example arrangement of a hydraulic valve operator on a horizontal butterfly valve.

(1) *Functional Testing*. When possible, the unit valve operator and unit valve should be functionally tested as an assembly before being installed at the powerhouse. Integration of the unit valve’s local controls and power system should be considered for this assembly test for risk reduction.

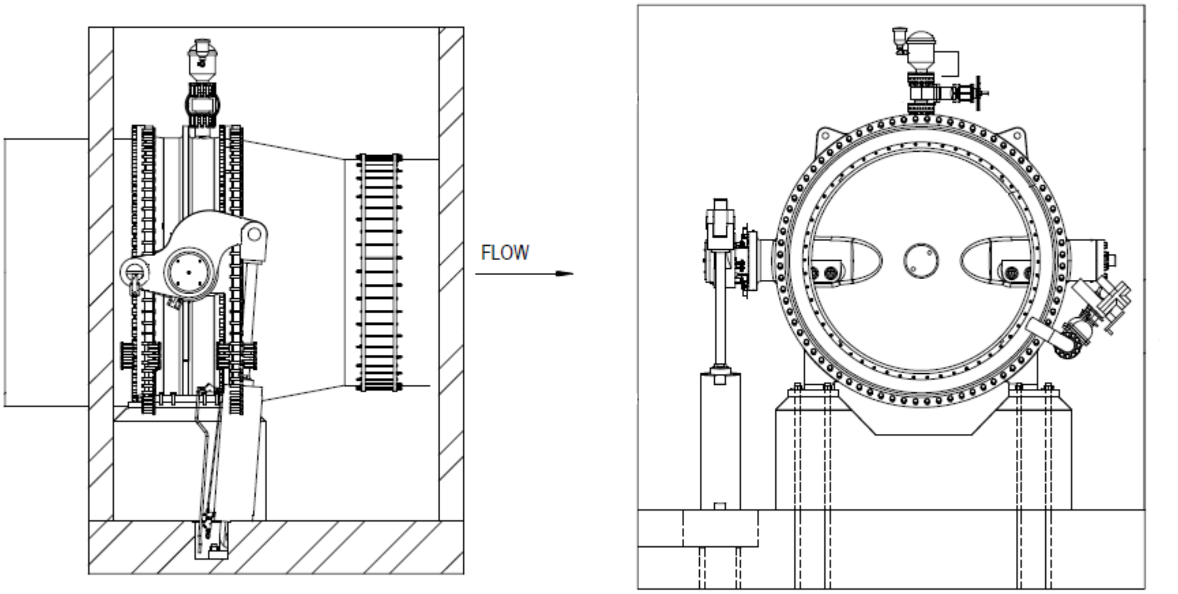


Figure 19–8. Side (left) and axial (right) elevation views of horizontal penstock butterfly valve with vertically mounted hydraulic actuator and exposed operator linkage

(2) *Hydraulic Operator*. A double-acting hydraulic cylinder operator is the recommended method to open and close the valve because it provides controlled hydraulic force in both directions.

(a) The operator should be capable of closing the valve at maximum pool head and maximum discharge. Opening capability should be at balanced head conditions. The operator should also be suitable for continuous pressurization to hold the rotor in either the fully closed or open position.

(b) All valve and operator components subject to loading from operator action should be designed for the maximum hydraulic cylinder forces with no localized deformation.

(c) Operator linkage may be exposed, as shown in Figure 19–8 and Figure 19–9 or in an enclosure, as shown in Figure 19–10 and Figure 19–11, regardless of disk orientation.

Figure 19–9. Vertical hydraulic valve operator for a horizontal butterfly valve with hammer-head closure weight (top)

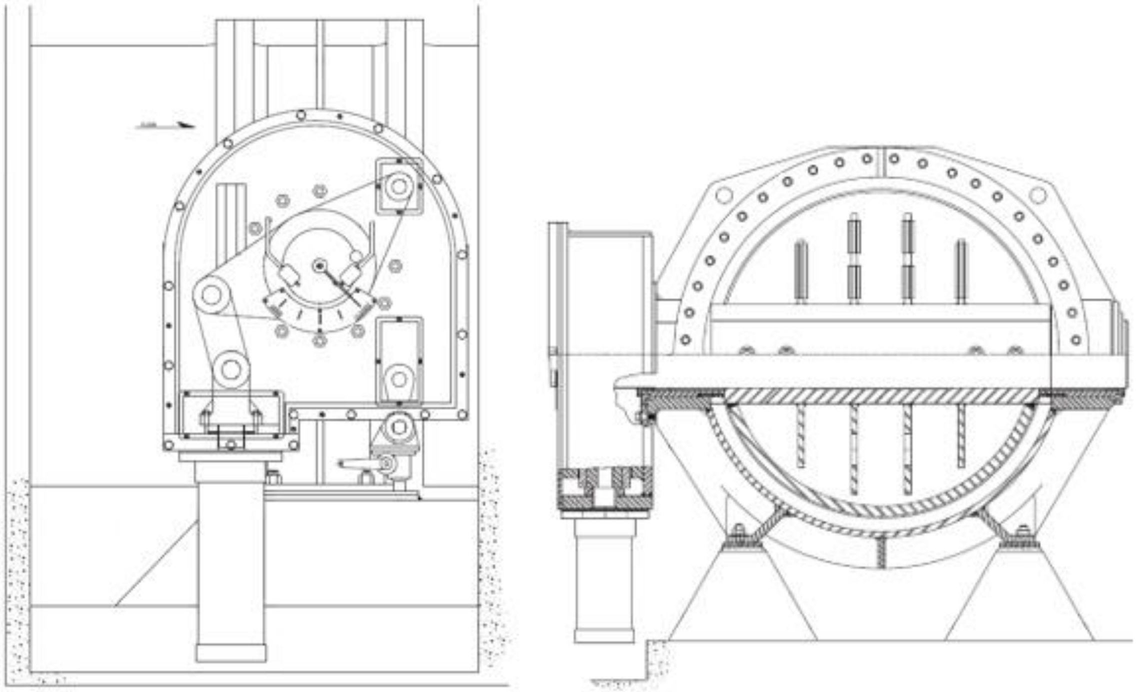


Figure 19–10. Side (left) and axial (right) elevation views of horizontal penstock butterfly valve with vertically mounted hydraulic actuator and encased operator linkage

Figure 19–11. Horizontal hydraulic valve operator for a vertical butterfly valve

(3) *Electric Motor Operator*. An electric motor driven operator with gearbox is an alternative method to provide for opening and closing the valve (see Figure 19–12 and Figure 19–13). When considering cost, layout limitations, safety measures and maintenance, this may not be the most preferred option. When procuring new valve

systems, most companies provide hydraulic-based valve operators due to simplicity in both operation and maintenance.

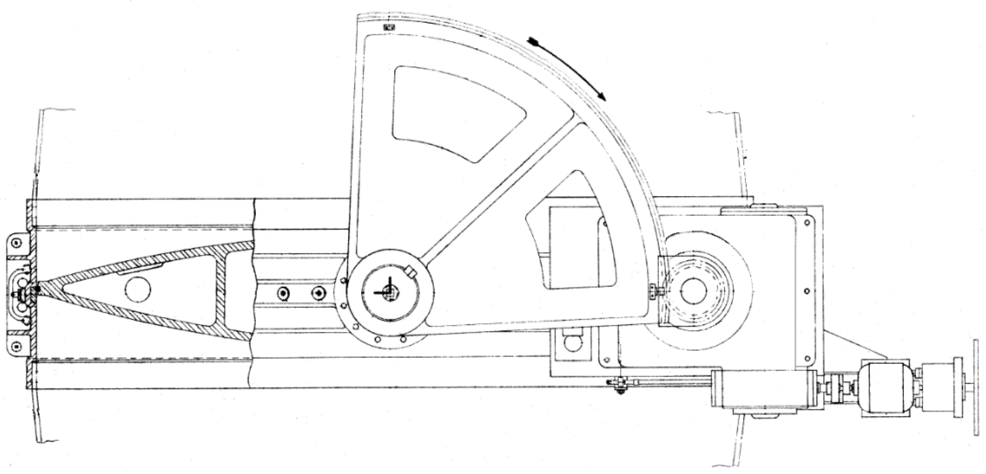


Figure 19–12. Plan view of vertical penstock butterfly valve with horizontal sector gear with electric motor driven operator

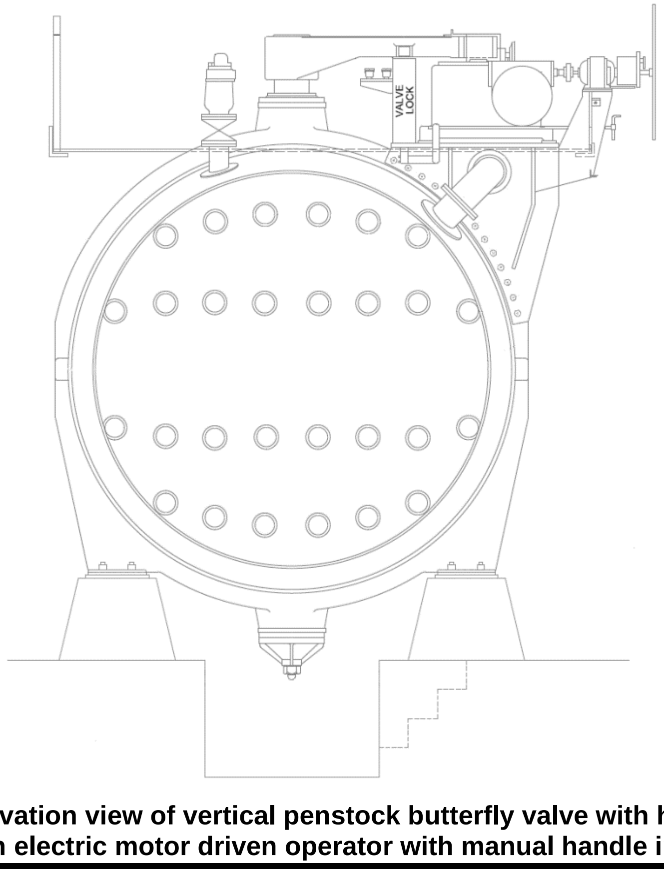


Figure 19–13. Elevation view of vertical penstock butterfly valve with horizontal sector gear with electric motor driven operator with manual handle installed

(a) The operator should be capable of closing the valve at maximum pool head and maximum discharge. Opening capability should be at balanced head conditions. The operator should prevent back driving and be suitable for continuous hold of rotor position in either the fully closed or open position.

(b) All valve and operator components subject to loading from operator action should be designed for the maximum hydraulic cylinder forces with no localized deformation.

e. Operator Control. The type of control should be appropriate for normal unit operation and emergency shutdown requirements. Solely manual operator control is not used with valves that are used for emergency closure of the waterway to a main unit. Both local and remote requirements need to be considered.

(1) *Local Control and Monitoring*. Local control and monitoring of most for the valve systems is in a dedicated control panel, usually located near the closure system's operator itself. This is because operation of the valve not only involves control and monitoring of the valve operator itself, but also the integration of other systems such as the bypass system (pressure monitoring and fill sub-systems), and other remote monitoring and control.

(2) *Remote Monitoring and Control*. It is common to provide monitoring and control of the systems located remotely from the primary control and monitoring location. Common remote locations are in the powerhouse's control room, the unit's governor cabinet, and connected to the unit overspeed switch. The control and monitoring capabilities at these locations are usually for only specific actions, not for fully redundant controls and monitoring. Examples include valve position and open/closure command.

(3) *Control System Integration*. A PLC system is recommended but not required for ease of integration of all the systems' controls and monitoring, and for future modification of the systems. Other arrangements that use switches and relays can provide a simpler approach to a monitoring and control system may be preferred by the project personnel from an operational and maintenance perspective.

(4) *Hydraulic Operator Control*.

(a) Use UFGS 35 05 40.14 for the hydraulic operator requirements.

(b) The hydraulic power system normally remains pressurized to prevent actuator drift while maintaining readiness for closure. Manual isolation of hydraulic lines or pinning of linkages should not be used to keep position of a valve unless the generating unit is taken out of service. Otherwise, the valve will not be readily available for an emergency closure or may be commanded to be in motion when they system is not fully functional.

(c) Using a combination of accumulators and pumps is the best approach to maintaining pressure within the hydraulic system at a level that allows closure of the valves. The accumulators maintain the pressure in the system while the operator maintains position. When the system pressure drops to a level set just above the minimal operating pressure needed to close the valve(s), the pump(s) are turned on to charge the accumulators. When the operator needs to move, the accumulator pressure is used to initiate movement and a pump turns on to provide the pressure and fluid flow to continue operator movement.

(d) A pressure-compensated, variable flowrate, axial piston-type pump should be used for the hydraulic operator power system. This pump type allows adjustment of the

maximum output pressure and is not negatively impacted when the actuator first begins to move and when it reaches a dead-head position. A fixed-displacement gear pump can be used, but the system controls must use an accumulator pressure during dead-head conditions to prevent over-pressurization of the pump case. These dead-head conditions are when the valve operator first begins to move and when it has reached its stopping position.

(e) Overall hydraulic operator system over-pressurization is prevented using relief or unloading valves in the system.

(f) A single hydraulic power unit (HPU) can be used to power multiple valves or separate power units can be used. Available space, distance between valve operators, and both initial and long-term costs should be considered when determining the HPU arrangement.

(g) Cylinder action is normally controlled with motor-operated, tight-sealing, four-way valves and pressure-compensated flow control valves set to obtain the required opening and closing times. Spool-type control valves are not suitable for extended pressurizing periods in one direction.

(h) Gauges, isolating valves, filters, alarms, control panels, and limit switches should be provided as applicable.

(i) System fluid filtration levels should be better than the recommended level of the most sensitive hydraulic control component. In addition to inline filtration, an offline (“kidney-loop”) fluid filtration system is recommended to reduce the likelihood of accumulation of particles due to the low duty cycles of these hydraulic systems and the low amount of fluid transfer during operator movement. Inline filtration systems require movement of the hydraulic fluid to remove particles.

(5) *Electric Motor-Driven Operators*.

(a) A brake should be used to hold the electric motor driven operator in place. Brakes should be motor mounted.

(b) Operator position indication and command should be provided as applicable.

(6) *Electrical Components*. Electrical components and enclosures should be designed for the environment to which they are exposed. If the components are located near the valves, they should be designed and manufactured for a wet environment. During assembly, the bolted slip-joint couplings with the penstock and scroll case extension require a seating period, which can result in external loss of water (see Figure 19–14). In addition, when the cavity downstream from the valve and upstream of the wicket gates fills as part of the normal penstock valve opening sequence, air followed by water sprays from the air/vacuum release valve. Most items in the same vicinity will be exposed to water spray.

f. Pipe Extensions.

(1) The penstock and spiral case extension should be designed on the same basis as the penstock, which is outside the scope of this chapter.

(2) One end of each extension should be provided with a flange to connect to the unit valve flange (see Figure 19–15). The flange connection must be a bolted connection. The other end of each extension should be prepared for a welded or bolted sleeve-type, slip-joint connection, as required. When required, the sleeve couplings are normally procured with the extensions.

(3) Some current installs have riveted connections between the valves and extensions (see Figure 19–16). This approach complicates refurbishment and replacement of the valves. Removed valves with rivets should be replaced with bolted flange connections.

Figure 19–14. Leakage into valve operator room from scroll case extension slip-joint during initial setting of joint

Figure 19–15. Flanged horizontal butterfly valve with bolted connection to penstock extension on left and scroll case extension on right

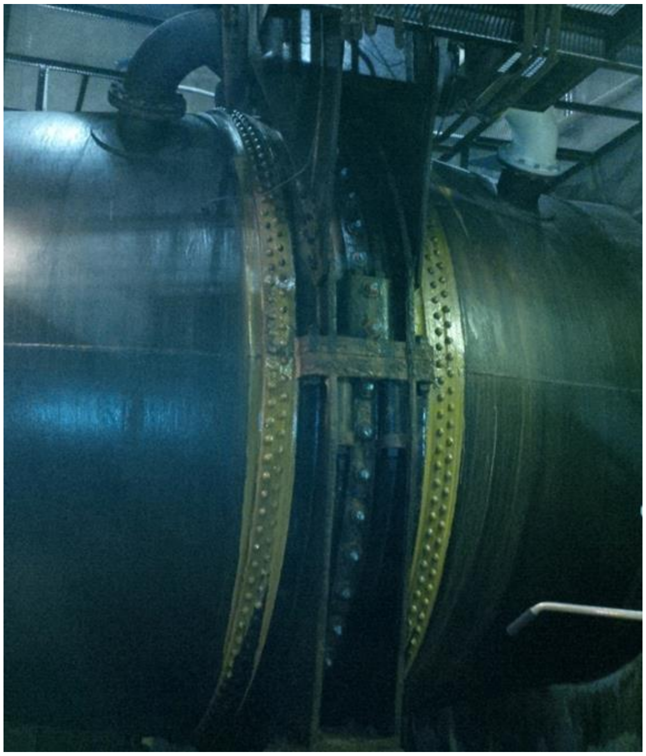


Figure 19–16. Vertical butterfly valve with riveted connection to both penstock extension and scroll case extension

(4) For new powerhouse builds or addition of a new valve system, the pipe extensions for connecting the valve to the penstock and spiral case extension are generally procured with the unit valve for the best design and manufacturing correlation.

(5) In some cases, it may be hydraulically justified to design the downstream extension as a transition section to minimize the effect of the velocity change at the valve. The downstream end of the transition section should be as required to permit the welded or sleeve-type connection to the spiral case extension (see Figure 19–17).

(6) For refurbishment or replacement of a unit valve, surfaces, gaskets, and paint leading up to the connecting flange should be included as part of the refurbishment. Check for any anomalies with bolt pattern or flange surface, as they may need to be accommodated by the replacement valve or during the refurbishment. The refurbishment contractor should be responsible for final interface performance if there are no issues with the existing interface before refurbishment or replacement.

(7) If the sleeve coupling is disturbed during any refurbishment or replacement, then the coupling seals and bolt assemblies should be replaced. If reused, each must be non-destructively inspected. It is common for the bolt shafts to have elongated and the seal section to have set, all presenting issues for the coupling to properly seal after reinstallation.

(8) An initially installed sleeve coupling is subject to external leakage and can require adjustment (see Figure 19–14). Only after the coupling has been fully watered can it be confirmed that the coupling has been properly installed and does not require further rework.

Figure 19–17. Flanged transition for valve to scroll case extension

g. Air and Vacuum Breaker Valve.

(1) The vacuum breaker valve assembly (see Figure 19–18) is located at the highest elevation of the unit valve. It releases air on filling of the cavity downstream of the unit valve and upstream of the wicket gates and allows air ingress to break the vacuum created during draining of the same cavity.

(2) A manual gate valve should be located as part of the valve stack-up to allow isolation of the air and vacuum valve from the unit valve for servicing activities without unwatering.

(3) Components in the vicinity of this valve assembly must be designed for water exposure because during the fill process, this valve will expel water during the closure seating of the air release valve. Where possible, surfaces should be shaped and angled to allow water drainage and prevent pooling that can have long-term impact to paint systems and base metals.

Figure 19–18. Air and vacuum breaker valve (black) with manual gate valve (red)

h. *Safety Provisions*.

(1) A lockable, mechanical means for constantly securing the unit shutoff valve in the closed position should be a part of the valve assembly. A common approach is to prevent motion of the valve operator, such a preventing linkage, gear, or actuator movement with a pin or collar (see Figure 19–19).

(a) The entire locking device assembly and interface with the valve should be capable of withstanding any opening force obtainable from the valve operator without any localized permanent deformation of any component. This is both to protect personnel from accidental opening of the valve, and for ease of unit return to service after an event.

(b) The arrangement should be such that engagement and disengagement of the locking mechanism can be visually confirmed from normal operating platforms or powerhouse floors without removing covers or modifying the assembly.

(c) Means can be a pin or latch assembly with jack screw.

Figure 19–19. Top view (left) and side view (right) of a pneumatically actuated locking pin with manual handle in a horizontal valve's hydraulic operator's exposed linkage

(d) System can be solely manual or mechanized. Mechanization can be accomplished with pneumatic or hydraulic power for pins, or a direct electric motor if jack screw. If mechanized, there must be a manual means to detach the lock from its operator, and to manually engage and disengage the locking mechanism. Solely manual means could be, for example, a manual pin into the operator rotating linkage or a threaded collar at the actuator.

(e) A limit switch or other electronic means should be considered for monitoring the locking mechanism engagement and disengagement position.

(2) Solenoid or other electronically operated control valves should have a manual means of operating the valve in either direction in case of loss of power or electronic control of the system.

(3) The valve operating cylinder design should include a cushioning feature to prevent damage to the cylinder and operator assembly due to the impact from a valve's rapid closure from rapid hydraulic pressure loss or other failure events.

(4) Additional flow control valves should be provided in the hydraulic circuit at the cylinders. These valves should limit the flow to 125 percent of normal closure flow if line pressure is lost. Provide for manual actuation in the event of a power outage.

(5) Hydraulic pumping capacity should be provided with two pumps in a lead-lag control arrangement, either of which can perform a normal opening or emergency closing.

(6) Fluid power from the hydraulic power system must have pad-lockable manual isolation valves that fully isolate hydraulic power from the valve operator cylinders. These isolations must be located so that they can be visually examined and accessed without any non-permanent means of access or elevation, or removal of components such as covers.

(7) Additional sources of power should be provided for unit valve emergency opening and closure with the operator. At least one means must be included for closure to prevent a single point failure from causing complete inoperability of the powering system.

(a) For a hydraulic operator, accumulators could be provided in the hydraulic system with capacity sufficient to fully close or open all unit valves on the system with both pumps inoperative after the low system pressure alarm has been activated. These accumulators are in addition to a normal accumulator that moves the actuator during normal operation and is assisted by the system pumps. Capacity should be sized for at least 1.5 closures. System reservoir must be sized to accommodate this additional fluid without over-pressurization or overflow. Each accumulator should have an isolation valve that is quickly accessible in addition to the isolation valve for the accumulator hydraulic pressure header. Access to charge, service, and other aspects of servicing the accumulators must be considered in the design and location of the accumulator arrangement. See Figure 19–20 for an example layout.

(b) A hydraulic hand pump can be included with the hydraulic power system to provide an additional means to actuate the valve operator's hydraulic cylinder. Practicality and time to open and close by such means should be assessed when determining inclusion of this feature.

(c) A drive motor that can use air, in addition to an electric motor, is another potential backup source if found practicable and if a readily available air source is present during an event.

(d) Direct injection of nitrogen or pressurized air into the hydraulic system can be a backup system. The hydraulic system needs to be designed and tested for this approach, with physical confirmation that the system can expel all of the gas without impact to performance or life of the components.

(e) A closure weight, such as the hammer-head design shown in Figure 19–21, can be used such that in the event of hydraulic power loss, the hydraulic operator will be biased to a closed position and the weight will cause retraction of the hydraulic cylinder and closure of the valve. This is usually deployed on a horizontal valve to avoid complex linkage designs.

Figure 19–20. Valve operator hydraulic accumulator bank with individual take isolation valves (bottom) and pressure gauge panel (right)

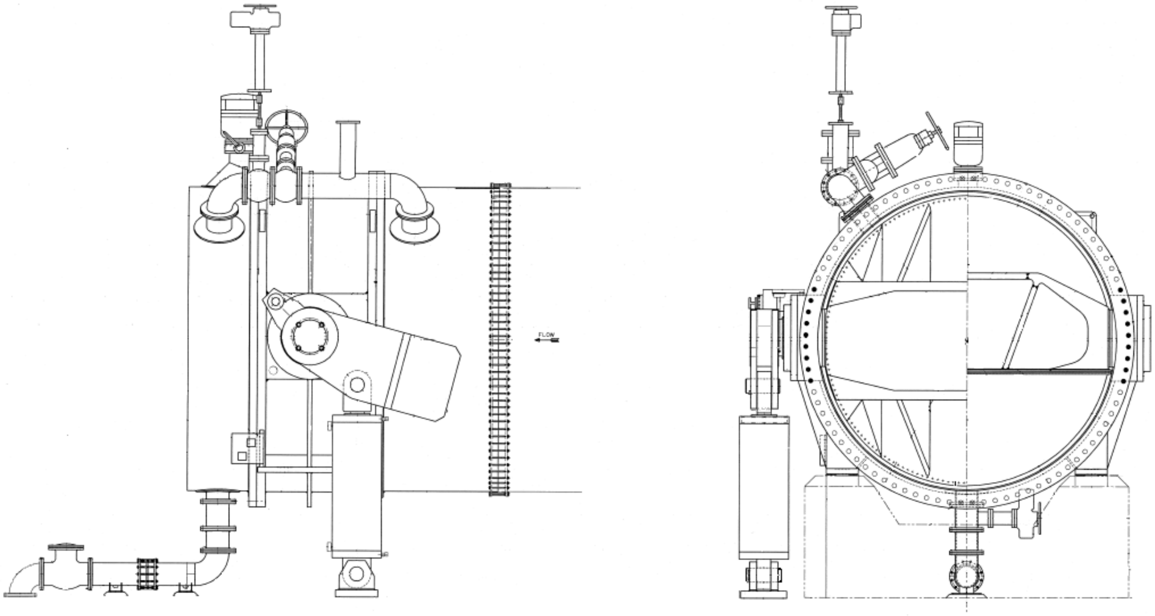


Figure 19–21. Elevation views of horizontal butterfly valve assembly with flow through disk design and hydraulic operator with hammer-head closure weight

(f) For an electrically motorized valve operator, the operator must have a manual means to move the valve. Using manual means must not be detrimental to the life of any of the assembly. A common approach is to have the capability to manually turn the electric motor drive shaft, usually with a hand wheel that is normally not installed but is located within the valve room. The motor should be designed and tested to allow this manual action without any reduction in operational life or requirement for additional maintenance. Figure 19–12 and Figure 19–13 each show a hand wheel installed on the electric drive motor.

(8) Valve bodies and rotors should be hydrostatically tested at 150 percent of design head in both directions and with rotors or disks open and closed.

i. *Access*. Safe access to operate and inspect the unit valve and its associated systems should be considered both for new builds and for refurbishment activities.

(1) The preferred approach is to provide platforms that do not require fall protection to access and use. This approach reduces fall hazards and increases the likelihood of on-time and thorough inspections. See Figure 19–22 for an example layout.

Figure 19–22. Platform access to valve operator and bypass valves that require no fall protection

(2) The unit valve disk locking system, air and vacuum breaker valve assembly, motorized bypass valve, manual valve, and inspection points of the unit valve operator are areas that should have safe access (see Figure 19–23 for an example layout). Any other components requiring inspection or access to examine or operate should have a planned approach for safe access. Any emergency operation aspects of the unit valve must have clear access to perform activities.

Figure 19–23. Platform access around air and vacuum breaker valve assembly requiring no fall protection

j. *Cast Component Inspections*. If components such as the valve body and valve disk (for butterfly valves) are cast, then all medium- and high-stress regions of that component must be non-destructively inspected for surface and sub-surface casting defects such as voids. Welding of cast iron is not allowed in high-stress areas, and acceptable only in medium-stress areas once assessment of impact, risk, and ability to inspect has been found acceptable to USACE. Welding and Metallurgy Technical Center of Expertise (TCX) (weldingmetallurgytcx@usace.army.mil) should be consulted to help develop welding procedure specifications (WPS), procedure qualification records (PQR) and weld testing for the acceptable welding on cast iron components.

k. *Containment*. All oil or other petroleum-based fluid containment equipment, such as hydraulic reservoirs, must have a means to contain the full loss of the oil that could be contained in the equipment, with additional margin. All oil or other petroleum-based fluid transfer equipment, such as piping, must have a means, such as a drip pan or containment trench, to prevent any point losses from leaving the powerhouse. See Chapter 29 for additional information.

19–7. Valve Refurbishment and Replacement Considerations

a. *Component Replacement*. As with any assessment of an existing installation, all components should be examined for performance issues and remaining useful life, then replaced or refurbished accordingly. If an item is replaced, the requirements and recommendations above apply.

b. *Penstock Valve*. The valve body and disk are generally designed for 50 plus years of life. Operating conditions can deteriorate coatings and base materials that reduce this length of life. High silt or brackish water impact the valve disk and internals of the valve body by removing coatings and material from the surfaces. External condensation and any external leakage lead to surface corrosion, especially in areas where the surface contours capture water instead of shedding it. See Figure 19–24 for examples of internal and external corrosion. The level of base material loss and impact to performance should be assessed to determine if the valve should be replaced. Unless the deterioration has cascaded into significant material loss, in most cases refurbishment of the valve is possible with removal of impacted areas and installation of a new coating system.

Figure 19–24. Valve disk (left) and valve body surface corrosion and operational damage

c. *Valve Sealing Systems*. Each valve has a sealing system for external leakage and a sealing system for the internal leakage.

(1) *External Sealing System*. The external sealing system, such as the trunnion seals of a butterfly valve, can see deterioration of seals that initially results in small external leakage. Always confirm that water or localized deterioration is from external leakage and not just accumulation of condensation. If unaddressed, the leakage will increase, with rate of increase depending on water conditions. Replacement of these seals can be labor intensive due to complexity of access, with vertical valves being the most complex. However, if external leakage is present, replacing seals and dressing sealing surfaces should be considered for a refurbishment event.

(2) *Internal Sealing System*.

(a) For the internal sealing system, refurbishment or replacement depends on the type of seal system design. Penstock shut-off valves have low cycles of operation compared to other valves in the powerhouse. Damage or reduction in performance of a system is usually due to damage from water and debris flowing through the unit.

(b) If the valve internal leakage is overwhelming the valve drainage system and allowing leakage down to the wicket gates, then the sealing system is no longer performing adequately. If there are areas of high concentrated flow with water upstream and the valve closed, the sealing system may have localized damage that requires replacement or refurbishment.

(c) Seal system adjustment capabilities should be used as a possible solution to the internal leakage past the valve disk that is exceeding an acceptable level. Bypass leakage levels are unacceptable when they present a safety risk or impact to maintenance activities, such as when the level of water exceeds the existing drainage capabilities, or when there is a high concentration of leakage (or high velocity). Metal-to-elastomeric seal systems are designed for adjustment of the elastomeric seal and ease of replacement if necessary. Metal-to-metal systems usually have discrete adjustment capability of one of the seals, with rework of the surface needed to match up with the interfacing seal. Replacement of a metal seal requires either significant overhaul to replace the segments or result in the need to replace the entire valve.

d. Valve Operator.

(1) Both the power and the actuating portions of the valve operator may be refurbished or replaced. Hydraulic actuators and gearboxes should be examined for signs of seal or running surface deterioration. The power system may need to be replaced or overhauled due to component end of life or to add safety features, monitoring features, or for revised function.

(2) If a replacement valve is procured, the valve operator should also be replaced and procured with the new valve as a complete system to avoid interface and performance issues.

e. Supporting System Valves. The bypass system valves, air and vacuum breaker valve assembly (including manual isolation valve), and drain valves deteriorate over time, with some having internal sealing issues and others having external leakage and corrosion at the stems. These valves should be assessed and either refurbished or replaced during an overall system overhaul.

f. Operator Controls. In most refurbishment or replacement actions, the valve operator is refurbished, modified, or replaced. The electrical controls usually have a 20-year-plus life span. In addition, modernized levels of monitoring and automating manual actions is generally found to be advantageous and may justify full replacement of controls.

g. Safety Provisions. All the safety provisions detailed for new builds should be considered for inclusion in a refurbishment or replacement project.

h. Access. The current layout of the penstock butterfly valve and its supporting systems should be examined to determine if additional or modified access should be added. Each of the noted access requirements and recommendations detailed above for the new valve assemblies should be examined for inclusion in the refurbishment approach. Ease of access for both operational and preventive maintenance should be considered.

i. Lubrication. Lubrication systems should be examined for performance issues and possible revision.

(1) External leakage of existing components is common for aging lubrication systems (see Figure 19–25). Fitting wear, seal and gasket degradation, and system over-pressurization are common causes of external loss of grease. It may be necessary to replace tubing, metering valves, or pumps to address system issues.

Figure 19–25. Valve grease pump and distribution manifolds (metering valves) leaking

(2) If distance, number of ports, or size of grease distribution locations are changed, the overall system should be examined to confirm that remaining components are adequate to consistently produce the needed quantity of grease at the required locations.

(3) Where technically feasible, new systems should be specified to use EALs. Equivalent performance throughout operational conditions must be provided when converting an existing lubrication system or replacing the system for a refurbished valve. When reusing any components of the lubrication system, or valve/operator that was lubricated, compatibility of the new EAL and all materials which interface with that EAL must be evaluated to determine measures to avoid adverse interactions such as degradation or corrosion. It may be necessary to replace components or take additional steps to ensure compatibility of materials with a new lubricant. Additionally, adverse interactions between a new lubricant and residue of the previous lubricant are possible; it may be necessary to remove the original lubricant to a level that presents an acceptable interaction.

Chapter 20
Load Handling Equipment

20–1. General

a. Introduction. Powerhouse load handling equipment (LHE) includes cranes, hoists, and lifting devices used in powerhouses for operational functions and for maintenance and repair. The general hoisting functions involved are similar for most powerhouses, but loadings, frequency of use, powerhouse configuration, installed equipment, value of downtime, and availability of portable equipment can affect the optimum provisions for a particular project. These factors typically require that powerhouse LHE be customized for the application. Normally, initial planning should be based on an existing project with similar requirements, but careful consideration of the variables should precede final design and selection of cranes, hoists, and lifting devices.

b. Purpose.

(1) This chapter provides background on hydropower crane and hoist applications, preliminary considerations for planning phases of powerhouse crane and hoist work, and guidance for the structural, mechanical, and electrical design of powerhouse LHE used for both new construction and rehabilitation work.

(2) EM 1110-2-2610 provides comprehensive guidance in the mechanical and electrical design of navigation lock and dam operating equipment and control systems for both new construction and the rehabilitation of existing projects; and should be reviewed in combination with this chapter for instances where the mechanical and electrical design criteria and guidance applies to the similar equipment used on hydropower cranes and hoists. It is not the intent of this chapter to re-state the design criteria guidance defined in EM 1110-2-2610, which covers similar equipment and requirements.

c. Terminology. “Cranes” and “hoists” are somewhat interchangeable terminology since the actual lifting mechanism of a crane is commonly referred to as a hoist. For purposes of coverage in this chapter, a crane is a machine for lifting and lowering a load and moving it horizontally, with a hoisting mechanism being an integral part of the machine. A hoist (sometimes referred to as fixed hoist) is considered as separate items of equipment that include installations where the hoist machine is fixed and there is no controlled lateral movement of the hook(s) or lifting block(s). A lifting device is a device, other than a load block, used for attaching a load to a hoist. In this chapter, when cranes, hoists, and lifting devices are discussed together they may be referred to as LHE.

d. Crane Types. Cranes for powerhouse requirements include several types: bridge, gantry, monorail, jib, mobile, and floor cranes. See the ASME B30 series of standards for additional crane definitions and terminology. This chapter covers the following:

(1) *Powerhouse Bridge Crane*. The principal overhead traveling crane in a typical indoor powerhouse that handles turbines, generators, and auxiliaries (see Figure 20–1). Typically includes a multiple-girder, moveable bridge carrying one or two movable hoisting mechanisms (such as a trolley) and traveling on an overhead fixed runway structure supported by concrete corbels or steel beams and columns.

Figure 20–1. Powerhouse bridge crane

(2) *Powerhouse Gantry*. A gantry-type crane serving the same functions as the powerhouse bridge crane for outdoor powerhouses or, in unusual cases, involving a special structural design of indoor powerhouses (see Figure 20–2). Similar to an overhead traveling crane except that the bridge for carrying the trolley or trolleys is rigidly supported on two or more legs running on fixed rails on the powerhouse floor.

(3) *Intake Gantry*. A gantry-type crane located on the intake deck of the powerhouse that handles intake gates, trash racks, trash rakes, intake bulkheads, fish screens, and other miscellaneous items (see Figure 20–3). The trash raking function is sometimes performed with a separate trash rake gantry crane.

(4) *Emergency Intake Gantry*. A gantry-type crane located on the intake deck of the powerhouse that handles intake gates and serves the primary purpose of turbine intake emergency closure (see Figure 20–3).

Figure 20–2. Powerhouse gantry crane

Figure 20–3. Intake gantry crane (left) and emergency intake gantry crane (right)

(5) *Draft Tube Gantry*. A gantry-type crane located on the tailrace deck of the powerhouse that handles stoplogs, bulkheads, and other miscellaneous items (see Figure 20–4).

Figure 20–4. Draft tube gantry crane

(6) *Monorail Crane*. A crane with underhung hoist, trolley-mounted, motorized or manual, running on an I-beam track or lower flange of a box girder (see Figure 20–5). This crane type is sometimes used for handling draft tube bulkheads at small powerhouses where the slot location is close to the downstream wall, and for other special applications.

Figure 20–5. Monorail crane

(7) *Jib Crane*. A wall- or pillar-mounted, rotating bracket with an electric or manual hoist for specialized lifts with limited horizontal movement requirements.

(8) *Mobile Crane*. A self-propelled, rubber-tired, or crawler crane for general use, principally on intake or tailrace decks and miscellaneous non-powerhouse project functions.

(9) *Maintenance Shop Bridge Crane*. A maintenance shop bridge crane, usually a trolley-mounted electric hoist suspended from a single girder bridge, serving equipment in the maintenance shop.

(10) *Floor Crane*. A light, portable crane with wheels for mobility on powerhouse and maintenance shop floor areas, normally manually propelled.

e. Hoist Types. Fixed-hoist applications in powerhouses typically include operation of intake gates requiring emergency closure capability, operation of gates and weirs requiring automatic or remote control, and miscellaneous lifts not accessible by a crane. Some powerhouses use fixed hoists to operate tailrace gates. Fixed hoists for powerhouse requirements are differentiated by two types: hydraulic hoists, and wire rope hoists. This chapter covers the following:

(1) *Hydraulic Hoist*. A hydraulic cylinder hoist that operates intake gates for emergency closure and for hydraulic-turbine generator unit maintenance and repair operations.

(2) *Wire Rope Hoist*. A wire rope drum hoist that operates intake gates for emergency closure, and hydraulic-turbine generator unit maintenance and repair operations. Usually found on intake configurations requiring gates with deep submergence or gates with shallow settings, either of which make hydraulic hoists undesirable.

f. USACE Powerhouse Cranes and Hoists Inventory. An updated database of USACE powerhouse cranes is maintained by the HDC. This database is updated regularly.

20–2. Crane and Hoist – Emergency Closure

a. General. Beyond the normal load handling function of crane and hoist equipment, there are three special applications that should be considered when evaluating existing or designing new equipment; these are emergency closure, gate cracking, and personnel hoisting. Following are the considerations for emergency closure.

b. Emergency Closure. Emergency closure is any intentional closure of the turbine intake under flow, other than by the governor controlling the wicket gates. The emergency closure system is critical to the safe operation of the powerhouse to protect against flooding, equipment damage, and loss of life. The likelihood of such emergencies is recognized as remote. However, the potential for major damage and loss of life does exist, and emergency closure provisions are justified. In every case, safety is the highest priority.

c. Performance Criteria.

(1) *Time*. Closure of all gates on a single unit should be accomplished simultaneously and within 10 minutes from initiation of the closure sequence. It is unclear when this policy was officially established, but available records indicate the 10-minute emergency closure time was initiated sometime in the 1950s. This determination

is based on findings in a 1988 report of meeting minutes from the Lower Granite and John Day Dam meeting on emergency gate closure times. This report reviewed allowable head gate closure times in emergency situations at Northwest Division (NWD) operating projects. The following is a summary of supporting evidence and additional background on the justification for establishing the 10-minute closure time (taken from the 1988 meeting minutes report).

(a) The 10-minute emergency closure time was believed to be initiated sometime in the 1950s when experience indicated that many turbine generating units, especially Kaplan adjustable blade units, could cause severe damage to the structure when operated at runaway speed. As a result, numerous runaway tests, required by acceptance tests to prove that the turbine generators were designed for and constructed to withstand the most extreme conditions, were waived when experience indicated eminent structural failure at less than runaway speed.

(b) Failure modes other than runaway were documented from investigations into actual events at Gavins Point, Big Bend, and Fort Randall that pointed to the possibility of a single shear pin failure that can cause loss of adjacent shear pins in a cascading or domino effect and result in the inability to shut down the unit with governor action. Operating a unit with gates swinging wildly on one side can cause turbine guide bearing failure, turbine runner contact with the discharge ring, and subsequent catastrophic failure of the turbine runner and head cover, resulting in flooding of the powerplant. In the event of this catastrophic failure, the intake gates must be closed as rapidly as possible—where 10 minutes is an established reasonable response time.

(c) The potential for damage to a unit as a result of runaway is both time and speed related. A paper titled “Runaway Speed of Kaplan Turbines” by G.H. Voaden refers to results of a runaway test at Bonneville First Powerhouse, and notes that significant damage can occur at speeds less than runaway if allowed to run for periods longer than 10 minutes (in this case the test ran for 30 minutes). The conclusion in this test provides further justification for the 10-minute closure time.

(d) Depending on the failure mode scenario, consequences could be severe in fewer than 10 minutes, or might take hours to days to become severe. Without a detailed potential failure mode analysis (PFMA) and flood rate calculations specific to each powerhouse, a specific number of minutes is hard to justify.

(2) *Speed*. The lowering speed of the gate at the point of contact with the sill should not exceed 10 feet per minute (fpm) (0.05 m/s), so as not to cause damage to the gate. Speed before contact with the sill can exceed 10 fpm (0.05 m/s), however, faster lowering speeds increase risk of slack rope if the gate becomes stuck (wire rope hoists only). Gate raising speeds are not critical. Depending on size, it is usually satisfactory to take 10–20 minutes to open a gate.

(3) *Power Supply*.

(a) Emergency closure should be possible under complete failure of the normal power supply. It is strongly recommended to have a backup power source available with minimal delays. For example, a diesel genset on the crane, or available to be hooked up to the crane at short notice, satisfies this recommendation.

(b) For hydraulic hoists that operate emergency closure gates, one possible scenario is to *both* lose primary power *and also* to lose pressurized hydraulic fluid. See paragraph 20–23b(3).

d. *Emergency Closure Conditions*. Potential conditions that could require emergency closure include loss of wicket gate control (such as unit runaway), head cover failure, an inadvertently opened or failed access hatch, or precautionary closures during abnormal operation.

e. *Emergency Closure Methods*. For safety reasons, two different closure methods to shut off the water supply to the turbine are required, both of which must be capable of repeated closures under flow conditions. One method is the wicket gates. The other method *must* be a penstock shutoff valve (refer to Chapter 19) or an intake gate lowered by a hoist. A fixed hoist is strongly preferred over a crane hoist for emergency closure. Backup systems that use compressed nitrogen to close the wicket gates in the case of a governor failure may be considered part of an emergency closure system, but do not take the place of the penstock shutoff valve or intake gate lowered by a hoist. See paragraph 20–2g for discussion on nitrogen closure systems.

(1) *Fixed Hoists*. Fixed hoists at each intake gate slot should be used to lower the intake gates in an emergency situation. The design should provide maximum dependability and rapid closure under remote control plus backup manual closure under power failure. In addition, necessary provisions for normal gate operations should be included. The hoisting system uses either hydraulic cylinder(s) or wire ropes.

(2) *Cranes*. Intake gantry cranes are not normally used to lower intake gates in an emergency because of the much slower response time (especially for a multi-unit powerhouse and units requiring two or three intake gates to shut off flow), in addition to the potential overload problems resulting from gate hydraulic downpull.

(a) *Overload*. The potential for overloading the intake gantry crane from gate hydraulic downpull is an important consideration for cranes used for emergency closure. This is because the designer must determine whether to size the rated capacity of the crane for maximum hydraulic downpull forces or select a lower rated capacity that treats loads from downpull as overload design criteria (see paragraphs 20–7 and 20–1d where the latter results in overloading the crane during maximum hydraulic downpull event). Overloading the crane during maximum hydraulic downpull may not be acceptable, especially in cases where maximum hydraulic downpull loads are calculated but actual loads measured by physical downpull testing have sometimes exceeded the calculated values, which adds additional uncertainty to the maximum overload the crane will experience.

(b) *Response Time*.

1. The critical time window to complete emergency closure depends on the nature of the failure(s) that occur. For many possible failure modes, the total time for a crane crew to come on site, pick up an intake gate, travel to the affected generating unit, lower the intake gate, and repeat the sequence to install the other two intake gates is much too long to avoid major damage to the unit and protect the integrity of the powerhouse. Even if the intake gantry crane is built with three hoists to carry three intake gates to provide faster closure, the response time is still too long.

2. Some USACE Projects do use intake gantry cranes for emergency closure; this increases risk for major damage, powerhouse flooding, and loss of life due to the much slower response time of cranes used in deploying intake gates in an emergency situation. Historical data on cranes used for emergency closure and the original justifications for doing so are discussed below.

f. Historical Data on Cranes Used for Emergency Closure.

(1) Approximately 25 percent of USACE powerhouses use intake gantry cranes for emergency closure.

(2) The original design reports or the feature design memorandums for these projects typically document the reasons and justifications for selecting a crane instead of fixed hoists for emergency closure. The decisions were typically based on economic analysis and value engineering proposals. The design decisions were historically based on the understanding that an emergency closure scenario is a low probability but high-risk event.

(3) Typical factors originally cited in the justification for using intake gantry cranes for emergency closure instead of fixed hoists are described below and may no longer be applicable. These factors increase the potential for a prolonged response time. Additionally, aging turbine-generator units and powerplant auxiliary equipment increase the likelihood of an emergency closure event compared to when the project was originally constructed. When intake gantry cranes used for emergency closure are considered for replacement, fixed hoists at each intake gate slot should be strongly considered.

(4) At a minimum, if intake gantry cranes are to be retained as the final means for emergency closure, the district should re-evaluate and validate the emergency closure response time, update the standard operating procedures accordingly, and confirm the process for deploying intake gates with a crane. These steps should be thoroughly documented and recorded, and all stakeholders should be made aware that using an intake gantry crane for emergency closure scenarios will take much longer than the prescribed 10 minutes afforded by fixed hoists (in some cases, multiple hours to deploy intake gates).

(5) The following factors were used for justifying cranes for emergency closure, and in many cases are no longer applicable—increased potential for prolonged response time.

(a) Projects that installed intake gantry cranes dedicated to emergency closure service no longer operate the cranes in this manner. This results in changing operating conditions where the gantry crane is being used for maintenance purposes at times when an emergency scenario occurs, instead of permanently staged with gate(s) connected and ready for emergency response—thereby increasing the emergency response time.

(b) Competent personnel capable of operating the crane under emergency conditions were to be on duty at the plant 24 hours a day. Power plant operators were considered a viable option to operate the crane during an emergency closure event, which is frequently no longer the case. Modern-day training requirements and labor agreements typically preclude power plant operators from being properly trained to safely operate the crane in an emergency scenario as originally included in the justifications for using a crane for emergency closure instead of fixed hoist.

(c) It was assumed the combined travel and action time for a competent person to begin operation of the intake gate crane would probably not exceed 5–10 minutes after notification. However, the actual time is likely longer (in some cases multiple hours), especially for operating projects that do not train for emergency closure scenarios.

(d) It was assumed one person could operate the crane and lower gate(s) into the gate slot without rigger assistance. However, due to the geometry of the gate slots and the configuration of the gate slot guides, it has been found that in practice at least one additional person (and possibly two or three people) is required to align gates with the slots until the gate is started/aligned in the guides. This is especially important for guides located in slots that are well below the intake deck surface and out of the crane operator's view, making it essentially impossible for the crane operator to deploy emergency intake gates by themselves.

g. *Wicket Gate Nitrogen Closure Systems*.

(1) At some powerhouses using cranes for emergency closure, a wicket gate nitrogen closure system is added as a backup method to close the wicket gates in the event of a governor failure or loss of pressurized oil. This system includes nitrogen bottles, valves, piping, and controls that, when initiated, discharge pressurized nitrogen gas into the closing side of the wicket gate servomotor piping to force the servomotors in the closed direction. A valve upstream of the connection from the nitrogen bottle discharge line into the wicket gate servomotor close line must be closed before the nitrogen gas is released for this system to be effective.

(2) The nitrogen closure system is ineffective for some emergency closure scenarios such as failed wicket gate shear pins and/or multiple failed wicket gates, ruptured penstock, ruptured headcover, and damaged/destroyed governor hydraulic piping. For these scenarios, an intake gate(s) must be lowered to shut off water supply to the turbine intake. The nitrogen system alone is *not* sufficient to fulfill the requirements for emergency closure.

20–3. Crane and Hoist – Gate Cracking

Beyond the normal load handling function of crane and hoist equipment, there are three special applications that should be considered when evaluating existing or designing new equipment: emergency closure, gate cracking, and personnel hoisting. Following are the considerations for gate cracking.

a. Gate cracking is the process of using the intake gate machinery or crane to slightly open the intake gate (approximately 3 percent open), thereby allowing water to flow into the turbine intake at a relatively controlled rate until achieving equalized pressure across the gate. This process is sometimes referred to as unit re-watering or refilling.

b. When a penstock or power tunnel is filled by cracking the intake gate, it is essential to fill the tunnel slowly to avoid sudden changes in pressure. The gate is raised at normal speed once pressure is equalized across the gate.

c. Units that have two or three intake gates will crack only one of the gates during the unit re-watering process.

d. Intakes using gates with upstream seals and a limited area behind the gates have developed dangerous gate-catapulting forces during filling. The risk and consequences of gate catapult increase with the differential head across the gate. See Chapter 27 for additional details and discussion with regards to unit equalizing (filling).

20–4. Crane and Hoist – Personnel Hoisting

Beyond the normal load handling function of crane and hoist equipment, there are three special applications that should be considered when evaluating existing or designing new equipment: emergency closure, gate cracking, and personnel hoisting. Following are the considerations for personnel hoisting.

a. Some cranes and hoists may need to lift personnel to perform inspection and maintenance tasks. This is a special application for powerhouse cranes and hoists, since they are traditionally designed as LHE and there are special provisions and safety requirements that must be considered when designing cranes and hoisting machinery to lift personnel.

b. Examples of permanently installed (as opposed to mobile) hydropower cranes or hoists used for personnel lifting are using intake cranes to lift personnel to inspect guides embedded in gate slots and using powerhouse bridge cranes to lift personnel to assist with turbine-generator disassembly and reassembly.

c. There are multiple standards, design guides, and regulations that govern LHE used for hoisting personnel. The primary ones are OSHA 1926.1431, EM 385-1-1, and ASME B30 series. Refer to EM 385-1-1 for current guidance on USACE cranes and hoists used for personnel lifting.

d. Prior to pursuing use of a crane to hoist personnel, it is the District’s responsibility to determine and document that a crane is the safest means to lift personnel for a specific activity, according to OSHA requirements.

20–5. New Installations – Preliminary Considerations (Project Planning Phases)

For each powerhouse, the following preliminary considerations should precede design and specification work on the individual cranes and hoists:

a. *Items Handled*. A preliminary list of all major items to be handled by powerhouse cranes during construction, operation, maintenance, and repair should be prepared and included in the design documentation report. The list should include estimated weights for load demand analysis and assessment, pickup and set down points, and the crane to be used. Also list below-the-hook (BTH) lifting devices used for each item.

b. *Area Layouts*. For each crane, layout drawings should be prepared showing points at which the crane must pick up or set down material, including loading or unloading of trucks and railroad cars, intermediate or transfer points, maintenance and repair areas, and equipment installation points. These layouts should include points for required lifts and points or areas at which crane lifts may be desirable but not required. Areas that may be used as storage or warehouse areas should also be indicated. Lifting or handling of heavy items (such as a small transformer), which may require moving and for which crane service is not planned, should be indicated along with the proposed means of handling.

c. *Coordination*. The list of items to be handled and area layout drawings should include information exchanged with construction and operation divisions as well as other engineering responsibilities. All reasonable adjustments in equipment location to provide effective and economical crane service should also be negotiated.

d. Miscellaneous Preliminary Considerations.

(1) Determine whether the crane or hoist will perform personnel lifting. See paragraph 20–4.

(2) Corrosion mitigation should be considered for outdoor gantry cranes, hoist machinery, and attached lifting devices and load blocks. See Chapter 38.

20–6. Existing Installations – Rehabilitation Versus Replacement Considerations

a. The information presented below is not to advocate replacing serviceable equipment, especially where not economically justified, but to provide information and historical perspective to help facilitate design decisions (for example, rehabilitation versus replacement of powerhouse LHE). HDC, project personnel, partner District, and stakeholders should work together to determine if existing equipment can be rehabilitated or must be replaced. The Project Delivery Team (PDT) should:

(1) Review the existing design and verify all original criteria (per paragraph 20–5);

(2) Review the load demand analysis and assessment (per paragraph 20–7);

(3) Review original design calculations and drawings and perform supplementary calculations and analysis of existing equipment to accepted design standards;

(4) Perform inspections of existing mechanical and structural equipment to be reused; and

(5) Verify the feasibility of the new equipment arrangements and all necessary interface details with existing equipment, then include appropriate details and notes on the drawings.

b. Common factors to consider when deciding whether to rehabilitate or replace powerhouse cranes and hoists include:

(1) If analysis of the existing design and equipment assessments reveal the structure and major mechanical equipment is suitable for continued operation and 50-year design life, then rehabilitation may be considered. Review EM 1110-2-2610 for guidance on evaluation of existing equipment and application of original design criteria compared to current and accepted design criteria and standards.

(2) Inspections of existing cranes should be performed according to ASME B30.2 and the inspection provisions found in the manuals supplied by the manufacturer(s) of the crane and the crane components.

(3) Inspections of existing wire rope hoists (fixed, stationary) should be performed according to ASME B30.16 and the inspection provisions in the manuals supplied by the manufacturer(s) of the hoist and the hoist components. Wire rope is considered a consumable and is not inspected during the project planning phase/scoping phase, since it should be replaced with new (unless it was very recently replaced).

(4) There is no industry standard for periodic inspection of hydraulic hoists like there is for wire rope hoists and cranes with the ASME B30 series. Generally, equipment should be visually evaluated for condition and damage, but additional non-destructive testing methods can be used if specific areas of concern need to be investigated further. Additionally, refer to the existing O&M manuals for additional inspection requirements.

c. Rehabilitation considerations specific to cranes and wire rope hoists are as follows:

(1) Typical machinery components that should be inspected with visual and NDE methods include, but are not limited to, wire rope drum end welds, load block hooks, hoist gears, and speed reducers. It is common to find cracks on spoked end drums. While a spoked drum end design was common practice, it is no longer recommended.

(2) Open gears and speed reducer gearing should be inspected for unusual wear patterns, damage, broken teeth, cracks, abnormal sounds, and vibration during operation. Gear covers should be removed. Open gear grease should be completely cleaned from the gears to allow adequate inspection of gear tooth roots, face, pitch line, and wear patterns. The gear tooth hardness of existing gears should be measured and compared to original design data. Use as-measured hardness values in American Gear Manufacturers Association (AGMA) gear rating calculations when assessing existing equipment for rehabilitation versus replacement. It is common to discover in-service gears that were not heat treated to the specified hardness, thus resulting in a lower than originally designed gear rating.

(3) Cranes, trolleys, and/or hoists that require heavy mechanical and structural retrofit work (such as drum and speed reducer replacements, machinery base modifications, trolley structure reinforcement/modifications) may not be good candidates for rehabilitation because of the high costs associated with retrofitting new designs to existing equipment (especially if done in the field). There is a point at which so much of the crane or hoist is being replaced that it makes sense to replace the whole crane because of the schedule and risk reduction.

(4) If the rehabilitation work scope is limited to electrical equipment and controls upgrades only, with incidental mechanical and structural work (such as replacement of wire rope), then rehabilitation is usually more economically feasible. Electrical equipment, motors, brakes, and controls are typically replaced during crane rehabilitations.

(5) Cranes used for emergency closure should be replaced instead of rehabilitated, unless a redundant crane is available to cover emergency closure requirements for the duration of the outage of the first crane, or unless an extended powerhouse outage is a feasible option.

(a) A new crane can be erected on site while the existing crane remains available for emergency closure, which allows turbine-generator units to remain operational. The new crane should be commissioned and made fully operational before removing the existing crane.

(b) If there is a need for intake deck crane rail refurbishment or replacement, the planning and scheduling of the rail work should be performed concurrent with the crane work. The new crane and existing crane can support emergency closure to operating turbine-generator units on opposite ends of the crane rail work areas until all rail work is complete, after which time the existing crane can be removed.

d. Rehabilitation considerations specific to hydraulic hoists are as follows:

(1) Hydraulic fluid age and condition should be evaluated using the testing methods described in EM 1110-2-1424. Intake gate systems generally see little fluid movement due to their infrequent use. As such, it is important to cycle the system to ensure oil is well mixed prior to taking the samples. Additionally, any available records

of previous testing should be gathered and evaluated. Multiple test results taken at different times (years) allows for evaluation of trends in the fluid condition and/or wear in the system.

(2) It is often difficult to inspect the interior surfaces of the hydraulic cylinders, piping, and appurtenances due to access issues or the difficulty in disassembling the equipment (especially applicable to cylinders). As such, the oil testing results can often be used to infer condition of other components. For example, wear particle composition can provide indication that cylinder walls or pistons are becoming damaged or wearing.

(3) Water intrusion is very common in intake gate hoist systems due to permanently submerged components. While water can cause issues with fluid performance and life, corrosion of steel surfaces is often a greater concern. Oil testing that shows high water content combined with wear particle composition containing corrosion byproducts is a good indicator that water intrusion is causing damage to components.

(4) While valves and instruments often have replaceable seals or can be rebuilt, it is often more economical to replace the component when considering outage time and the effort required to disassemble and rebuild the component.

(5) If a fluid change is being considered (brands or type of fluid), then compatibility testing should be performed between the existing fluid and the proposed new fluid. It is practically impossible to clean all traces of the existing fluid from existing components and compatibility testing helps avoid negative interactions between the two. Additionally, compatibility with all sealing material should be checked. Since seals are considered a wear item and periodically replaced, they should be replaced regardless of compatibility testing results.

(6) Flexible hydraulic hoses have a significantly shorter design life than most other components in the hydraulic hoist system. All hoses should be replaced during a rehabilitation project unless it can be proven they have been recently replaced through a separate effort.

e. Often, crane and hoist rehabilitation contracts result in longer outages and increased impacts to project operations when compared to new crane and hoist replacement contracts.

(1) New crane replacement contracts typically allow the existing crane to remain in service while the new one is designed, manufactured, factory tested, delivered, installed, commissioned, load tested, and made ready for service. Installation location is typically on the same rails but at one end of the powerhouse. This limits impact to project operations and use of the existing crane, and an overall reduced outage duration. Unless an extended outage of the powerhouse is an option, emergency closure cranes should be replaced rather than rehabilitated.

(2) New hoist replacement contract durations are similar to the discussion above for new cranes, except once the delivery of new fixed hoist machinery is on site, the existing hoist and operating unit requires an outage to remove the existing fixed hoist machine and install the new hoist. This is still usually an overall shorter outage duration and less impact to project operations compared to refurbishing existing mechanical and structural equipment, which is typically done by shipping offsite.

(3) There is a higher probability for unforeseen site conditions during rehabilitations versus replacements, which can lead to construction cost increases and schedule

delays. These risks can be mitigated by performing inspections during design and planning phases referenced above. However, there are always unknowns going into crane and hoist rehabilitations because disassembly of equipment in the load path of the crane/hoist for a thorough inspection requires an outage and load-test on reassembly. Normally, the risks of unknown condition of components in the load path are preferable to the extra expense and outage time for disassembly and load-testing.

(4) Providing service-ready cranes on schedule is very important to avoid impact to overall powerhouse construction schedules, plant operations, seasonal operation restrictions (such as fish passage seasons), and follow-on powerhouse construction contracts. Contractors inexperienced in design and construction of custom crane and hoist machinery have caused costly delays and impacts to other construction work.

20–7. Crane and Hoist Load Demand

a. Coordination. The design of powerhouse crane and hoist equipment requires close coordination between HDC and the project to determine the operating equipment loading, which is necessary for specifying the crane/hoist rated capacity. The design team must determine the types of loads and maximum loads that the crane/hoist will experience during load handling operations.

b. OSHA Regulations. Current OSHA regulations do not permit regular overload of a crane or hoist. For these reasons, it is necessary to verify the maximum load demand on a crane/hoist before deciding to rehabilitate or replace a crane/hoist, rather than rely on the original rating being adequate.

c. Load Demand. Load demand information provided on crane and hoist drawings used to develop the original crane/hoist rating is usually based on original calculations and estimated weights of the heaviest lift (such as turbine and/or generator parts, gates and/or bulkheads). These values were frequently not updated to reflect final fabricated weights. Also, lifting beam weights were sometimes omitted from the original demand calculations. For cranes/hoists that handle gates and/or bulkheads, assumptions regarding friction, silt, and downpull were frequently not verified in the field following final completion. It was typical to rely on the cranes or hoist’s overload capacity to handle any discrepancies. It was also common practice to allow the crane/hoist to be routinely overloaded by up to 10 percent compared to calculated load demand (or rated load of the crane/hoist).

d. Load Demand Initial Step. The initial step in verifying load demand is to calculate load demand based on final as-constructed drawings of the heaviest lift (such as turbine, generator, gates, bulkheads), and any external influence on the lifted load such as gates/bulkheads operating in their slots.

e. Load Demand Final Step. The final step is to physically verify the loads on the crane/hoist by weighing with calibrated load cells or an equivalent system, when feasible. There are potential errors in assumptions used in original calculations and in the methods used to measure loads on a crane/hoist. For this reason, the new calculated weights and friction forces are compared to the physically measured loads and to the original crane/hoist data before making a final recommendation for rated load.

f. *Crane Capacity*. The design crane/hoist capacity that is based on the load demand analysis and assessment should be conservative, reflecting the indeterminate nature of major loads.

g. *Additional Considerations*. The following are additional considerations for determining maximum loads on powerhouse cranes and hoists (with additional discussion on calculation methods, assumptions, and considerations for physical testing to measure loads):

(1) For powerhouse cranes, obtain accurate weights for turbine and generator weights. Contact the HDC for current and updated records of turbine and generator weights.

(2) For cranes and hoists handling gates and/or bulkheads, the general considerations for load demand assessment and analysis are as follows:

(a) Intake and draft tube gantry cranes and fixed hoists that handle intake gates and/or bulkheads are subjected to a variety of external forces that influence the maximum loading, and the load demand analysis and assessment for this operating equipment usually requires calculations, and in some cases physical testing, to measure downpull loads or seal breakaway loads during gate cracking.

(b) A quantity take-off is used to estimate the dry and buoyant weight of the gate or bulkhead. This is performed using the final as-constructed drawings of the gates and bulkheads. The same as-constructed drawings are then used to calculate the volumes that can accumulate in each web for estimating water and silt weights. The following values for specific weight are used in calculating load demand:

1. Water: 62.4 lbs/ft^3 (9.80 kN/m^3).
2. Steel: 490 lbs/ft^3 (76.97 kN/m^3).
3. Silt: 125 lbs/ft^3 (19.64 kN/m^3).

(c) Original calculations, design memos, and as-constructed documents are used in estimating downpull. Downpull is discussed separately in upcoming paragraphs.

(d) The as-constructed drawings of the gate or bulkhead slots are compared to the gate or bulkhead to verify the assumed compression of the springs (for bulkheads) and horizontal force on the seals (both gates and bulkheads). These horizontal forces are then multiplied by the respective coefficient of friction to obtain the friction demand on the crane or hoist.

h. *Intake Gate and Bulkhead Forces*.

(1) *Horizontal Seal Compression/Deflection Force*. The seal compression force (or deflection force, depending on seal arrangement) is evaluated based on data from the seal manufacturer catalog data, and friction is calculated from this compression (or deflection) force.

(a) J-bulb type seals are commonly used on the top and side seals for lower head gates and bulkheads. These J-bulb type seals should be arranged such that water pressure deflects the stem of the J-bulb toward the sealing contact bar embedded in the slot. Some J-bulb seals are detailed such that the stem is not allowed to deflect, and the bulb is then compressed against the sealing contact bar. Horizontal forces of seal compression significantly exceed deflection forces and impact seal friction and the design of the leaf spring.

(b) Center-bulb type seals are used more on higher head gates and do not deflect, but detailing should allow water pressure behind the seal to improve sealing. Air bladder systems behind these types of seals can be used to improve sealing but can be troublesome to maintain.

(2) *Horizontal Leaf Spring Compression Force*. Leaf springs are tempered steel flat bars bent into a curved shape and are used on bulkheads to assure bulkheads seals are provided with sufficient preset horizontal force for the seals to engage with the sealing surface of the slot. Typically, leaf springs are secured to draft tube bulkheads with retainer clamps that allow the springs to stay in place while still flexing freely. The height of curvature of the leaf spring and the fit of the bulkhead within the bulkhead slot, together with the design of the seals (J-bulb compression versus stem deflection) and bearing bars, determines the amount of horizontal force supplied by the leaf springs.

(a) These components should be evaluated as a system (leaf spring, seal, bearing bar) in equilibrium. Once the amount of spring deflection is determined, simply supported beam formulas can be used to predict horizontal spring forces, which can be used with coefficient of friction values for steel-on-steel contact to determine leaf spring friction forces, which oppose the direction of movement for the crane or hoist.

(b) Over time leaf springs can degrade, become flattened, be over-restrained at the ends, or, when replaced, have more curvature (interference with the bulkhead slot) than allowed in the original designs for the bulkhead. These changes can significantly alter spring friction forces and adversely impact loads on hoists.

(3) *Friction Forces, General*. Friction forces are difficult to accurately predict. Friction varies greatly, depending on material surface condition, slot dimensional variation, the tendency for seals to form a contact bond when kept under tight compression for an extended period of time, and machine fit for roller and wheels. For bulkheads, the friction demand comes from the seals themselves and any contact with bearing shoes or end guides, and for draft tube bulkheads, the leaf springs used to engage the seals. For emergency intake gates, which are equipped with roller chains or roller wheels to allow closure under flow, the friction demand comes from the seals and from roller and bearing friction.

(4) *Friction Forces, Seals*. The gate/bulkhead seal friction is a function of the preset force in the seal and the hydrostatic pressure on the seal surface. The seal friction should be evaluated for both static and dynamic conditions. During gate and bulkhead raising, seal friction is an additional loading on the hoist machinery caused by sliding friction of the wear surfaces and seals against the stationary mating structure surfaces. In the application of emergency gate closure, seal friction acts in the opposite direction of hydraulic downpull and gate weight, reducing the total force acting on the hoist machinery. The engineer should consider the following when determining seal friction loads.

(a) The type of coating surface on the bulb seals on the gate being analyzed must be identified. For example, polytetrafluoroethylene (PTFE, also commonly known as Teflon) cladded versus bare rubber. Some gates use PTFE cladded J-bulb seals to reduce friction loads during gate cracking operations. PTFE cladded seals significantly reduce the amount of seal friction due to its lower coefficient of friction compared to bare rubber. A common value for static friction coefficient for rubber seals is 1.0 to 1.1.

A common value for moving (dynamic) friction coefficient is 0.7. The static and dynamic friction coefficient for PTFE cladded seals is 0.1.

(b) When introduced into gate seal design, a PTFE cladded seal was intended to be used only on the top horizontal seal to assist with initial breakaway forces for gate cracking operations. However, some powerhouses have also replaced the side seals with the PTFE cladded seals, not realizing that doing so increased the load demand on the hoist equipment by reducing the friction that counteracts the downpull force. PTFE cladded side seals increase the total force on the hoist machinery during gate closure under flow.

(c) Example calculations for seal friction load derivation are provided in EM 1110-2-2107 and EM 1110-2-2610.

(5) *Friction Forces, Rollers* (tractive load). The two types of rollers on vertical lift gates that contribute friction forces are roller chain and fixed wheels.

(a) Roller chain (also referred to as roller train, tractor, or caterpillar-type end support for vertical lift gates) is a continuous chain constructed of steel rollers, axles, link plates, and clips that, when assembled, wraps continuously around both sides of the intake gate. These are more commonly found on emergency closure gates or gates that control flow under high head. Since load transfer is achieved by uniformly distributed bearing through the small rollers, they are able to withstand large horizontal loads while being lowered under full hydrostatic head.

(b) The main advantages of roller chain over fixed wheels include a lower friction component while hoisting under load, lower bearing stresses transferred to the guides and gate framing, and shear and bending not transferred to the gate through the axle. The load is transferred from a bearing surface on the gate, through the rollers, to the guide-bearing surface on the monolith. The entire roller chain is independent from the gate and the guide, which allows free movement of the roller chain.

(c) There are two components of friction due to the rollers on the intake gates: rolling friction and bearing journal friction. Roller and bearing friction can be calculated for four cases:

1. Static friction, unit unwatered.
2. Dynamic friction, unit unwatered.
3. Static friction, unit at tailwater.
4. Dynamic friction, unit at tailwater.

(d) The roller friction load applies to intake and draft tube cranes and hoists that handle vertical lift gates with roller chain that must close under flow. The total friction due to the gate reaction rollers running against steel tracks and the friction of the bearings in the reaction rollers is much lower than sliding friction surfaces. This is taken as 5 percent of the load normal to the gate leaf as defined in EM 1110-2-2610. Roller friction loads from fixed wheel gates serve a similar function as roller chain. See EM 1110-2-2107 for additional discussion on vertical lift gate end support types.

(6) *Draft Tube Bulkheads*. For draft tube bulkheads, an additional consideration for seal friction is determining how much of the seal is in contact when a bulkhead is ready to be pulled from the slot. In some draft tubes, an air pocket forms against the top horizontal seal and as the draft tube is filled with water. the air is forced past the seal, causing it to no longer contact the slot. Project staff can anecdotally confirm this phenomenon.

(7) *Differential Head.* An additional variable in calculating friction load demand is differential head. On turbines with high wicket gate leakage, it is not feasible to achieve balanced head across the gate or bulkhead. Differential head on the order of 4 ft (1.2 m) has been observed on some units within USACE.

(8) *Seal Breakaway* (during gate cracking).

(a) Normal gate movements are made under balanced head conditions and usually involve essentially only gate buoyant weight, rod buoyant weight (hydraulic cylinder hoists only), seal friction, and roller chain tractive load. The seal breakaway load (during unit re-watering) is composed mainly of gate deadweight, seal friction, roller chain or wheel tractive load, and hydraulic cylinder rod weight (hydraulic cylinder hoists only). The contribution of breakaway loading to design hoist capacity should be conservatively estimated, due to its variable nature.

(b) Seal breakaway friction tends to be unpredictable as it depends on type of seal, surface condition, seal material, elapsed time with seal under head, and seal preload. However, it can be of greater magnitude than the maximum downpull forces. Maximum downpull load does not occur simultaneously with seal breakaway load.

(c) If possible, the seal breakaway load demand, during gate cracking operations, should be physically verified using the current crane/hoist equipment.

(9) *Hydraulic Downpull*.

(a) The emergency closure load is composed mainly of gate weight, hydraulic downpull load resulting from high-velocity flow under the gate, head on the gate upper seal, and weight of hydraulic cylinder rod when gate is operated by hydraulic hoist. Hydraulic downpull varies greatly, depending on configuration of the gate bottom, static head, location of the skin plate and seals (upstream versus downstream), and friction. In most cases, the load caused by the hydraulic downpull is the major load that the hoist will see in emergency shutdown. Extreme care must be taken when determining these loads.

(b) More information on hydraulic downpull can be obtained from the HDC. It may be possible to physically verify the downpull loading using the current crane/hoist equipment, however this type of testing should be performed with extreme caution. This type of testing must also be carefully coordinated with engineering to ensure the test is performed safely to avoid damage to the crane/hoist and the turbine-generator unit.

(10) *Silt*. Additional weight due to accumulated silt should be added to the overall load of the hoisting machinery. The silt can become trapped above the web of the girders to the height of the flange. Calculate the weight from the possible storage volume on the gate, using a silt density of 125 lbs/ft^3 (19.64 kN/m^3).

i. *Vertical lift gates*. The engineer should review EM 1110-2-2107 and EM 1110-2-2610 for additional discussion of the types of loads on vertical lift gates and gate hoist loads (typical calculations for determining loads for design of emergency gates are provided in the appendixes of EM 1110-2-2610).

20–8. Engineering and Design – General

a. Engineering and detail design criteria for hydropower cranes and hoists are covered in this chapter and referenced chapters from EM 1110-2-2610. Final detailed design and construction of cranes and hoists are often the responsibilities of the supplier as provided under the procurement contracts. The responsibilities of the design team for cranes and hoists typically includes but is not limited to the following:

(1) Obtain and coordinate all preliminary information noted in paragraphs 20–5 and 20–6 as appropriate.

(2) Determine requirements for each crane or hoist based on the preliminary information.

(3) Prepare crane/hoist clearance and coverage drawings based on sufficient design studies.

(4) Ensure the technical portion of the procurement contract specifies a practical and economical crane or hoist that meets all requirements.

(5) Documentation of assumptions and reasons for selecting crane/hoist rated capacity should be part of the design records. Rated capacity is the maximum load for which the crane or individual hoist is designed and built with no specific limit on number of lifts per year. Documentation of assumptions and reasons for selecting particular lifting procedures and equipment arrangements should be a part of the design records. The preliminary studies and coordination are important in obtaining the optimum crane for the required service, and shortcuts should not be made.

b. Cranes and fixed hoists used in hydropower must perform safely and reliably under stringent operating conditions over a 50-year design life. Each powerhouse has unique site requirements (such as rail gauge, large crane rated capacities, extreme vertical lifts for gates with deep submergence, tandem lift requirements, crane access constraints and clearances), and there is a wide variation between powerhouses. The cranes and fixed hoists that service the unique site requirements typically require designs with significant customization to meet operating demands and conditions of the powerhouse.

c. Most cranes and fixed-hoist machinery used in powerhouse applications that are servicing the unique site requirements are not commercially available, commercially purchased systems. To meet the need for site-specific customization, design criteria should be developed for each unique crane and fixed hoist to assure safe, reliable operation. This requires USACE to develop design criteria in significant detail to obtain reliable cranes and hoists that are successful for long-term use.

d. The HDC develops and maintains the basic design criteria for hydropower cranes and fixed hoists after considering historic crane guide specifications, modern crane design guides, and current industry crane safety codes and standards. The design criteria are routinely updated with lessons learned from hydropower crane/hoist rehabilitation and replacement contracts. Updated criteria are also deliberately conservative to assure a safe, reliable design.

e. For smaller capacity cranes not requiring customized designs, such as maintenance shop bridge cranes and jib cranes, there are typically commercially available products, with multiple nearly identical copies being produced. Commercially available products have reasonable product development with associated costs spread over the production run. Competition among multiple manufacturers also drives down the cost. Crane manufacturers, like other commercial product manufacturers, do not disclose their design criteria, which likely varies. When there is uncertainty regarding the design criteria used by manufacturers of commercially available smaller capacity cranes, consider buying the next size larger to ensure conservative design for the application.

20–9. Engineering and Design – Specifications

a. Several guide specifications and industry design documents are available for cranes, hoists, and BTH lifting devices. These specifications should be considered when preparing technical specifications for new equipment procurements and crane and hoist rehabilitation projects. The Navy also has design specifications and standards including Navy Crane Center, NAVCRANECENINST 11450.2A, Design of Navy Shore Weight Handling Equipment.

b. EM 1110-2-2610 includes a list of available UFGSs that are developed for commercial crane and hoist procurements (typically with packaged hoist systems and rated capacities less than 30 tons). The UFGS crane guide specifications are suitable for crane procurements that do not require design customization to address unique site requirements and load handling operations and are not subject to special hoisting applications (emergency closure, gate cracking, personnel hoisting, etc.) and abnormal loading conditions.

c. The UFGS crane specifications are typically used for small-capacity cranes and hoists for which there are commercially available products. They are suitable for use in crane procurement contracts that do not require the prescriptive crane design specification details, and manufacturing, testing, and commissioning requirements that are discussed in the following paragraphs.

d. Detailed prescriptive plans and specifications should be prepared for large-capacity custom hydropower cranes and hoists. This includes cranes with capacities greater than 30 tons and for certain smaller capacity (10–15 ton) cranes such as outdoor draft tube gantry cranes with unique site requirements. The detailed prescriptive plans and specifications are recommended due to the limited contractor pool of highly qualified crane manufacturers with experience designing and fabricating large-capacity custom crane and hoist machinery. The UFGS crane guide specifications are not recommended for use for large-capacity custom hydropower cranes and hoists.

e. Crane specifications for custom designed cranes should provide detailed prescriptive requirements for crane performance, design, manufacturing, materials requirements, paint and welding requirements, factory testing, critical hold point inspection requirements during fabrication, crane erection, commissioning, and load testing. Detailed criteria on crane design submittal requirements should be included, providing minimum requirements for machinery calculations, crane structure and stability design analysis, electrical design, equipment product data, and shop drawings. Requirements should be included for design submittals to be reviewed and approved by the Government.

f. The HDC maintains a series of prescriptive crane guide specifications that are available to designers on request. These HDC crane guide specifications are updated periodically and include specifier notes and design guidance to engineers writing specifications for new crane and hoist replacement and rehabilitation projects. The HDC crane guide specifications are expanded from the legacy crane guide specifications (such as CE-1603 for draft tube gantry cranes, CW-14330 for indoor bridge cranes, and CW-14340 for dam gantry cranes) and updated with crane/hoist replacement/rehabilitation contract lessons learned, and updated crane design guides and industry crane safety codes and standards. The HDC crane guide specifications typically cover the following major categories in crane design, manufacturing, installation, and testing:

(1) Steel welding and fabrication for cranes.
(2) Metals: Materials, products, and miscellaneous items.
(3) Paints and coatings for cranes.
(4) Crane data, testing, and training.
(5) Crane mechanical and structural work.
(6) Crane appurtenances.
(7) Crane electrical work.
(8) Below-the-hook lifting devices.
(9) Crane rail replacement/repair.

g. Most USACE powerhouse bridge cranes, powerhouse gantry cranes, intake gantry cranes, draft tube gantry cranes, and fixed hoists require prescriptive design specifications with detailed contract drawings.

h. No specific USACE crane design EM has been developed, however, there are multiple industry standards and design guidelines available. EM 1110-2-2610 includes a list of industry design documents to be considered a starting point for specific crane design. The ASME B30 series of standards provides specific design guidance and minimum safety requirements for several crane types, including overhead and gantry cranes (B30.2), and hoist types, including overhead underhung and stationary hoists (B30.16). The ASME B30 standards should be considered a starting point for specific crane and hoist design (even though they state that they do not apply to guided loads). Crane Manufacturers Association of America (CMAA) 70 provides the principal industry design guidance for the powerhouse bridge and gantry crane and is routinely referenced in the USACE crane design specifications.

i. Crane designers, fabricators, and prime contractors must have experience in designing, fabricating, erecting, and commissioning cranes. Requirements for contractor’s crane experience should be included in the specifications for all custom crane procurement contracts. The crane design and operation have direct impact to life safety, which must be the overriding requirement in any design and procurement. The crane must be stable for all operations. The safety and health requirements in EM 385-1-1 must be followed and all cranes must include safety features such as load indication, load control, anti-two block indication, and load-limiting devices.

20–10. Engineering and Design – Drawings

a. The design team should prepare clearance and coverage drawings for new crane/hoist procurements and equipment rehabilitation contracts. The coverage drawing includes the minimum envelope that the crane can service with the hoist(s), factoring in the limits of bridge-gantry travel and trolley travel (as applicable) with bumpers uncompressed. All PDT members should agree on the final prepared clearance and coverage drawings to ensure the new/rehabilitated equipment meets the operational requirements of the project.

(1) The minimum clearance is the distance from any part of the crane/hoist to the nearest obstruction. For existing cranes/hoists that are being rehabilitated or replaced, the design team should consider assessing existing working clearances by field measurements and review of as-built drawings. The designer should dimension the minimum clearances on drawings. Also, assure compliance with minimum requirements defined in CMAA 70 and ASME B30.2, and account for factors that influence minimum clearances such as wheel float or bridge skewing.

(2) Consult the HDC for example bridge crane clearance diagrams and coverage diagrams of typical powerhouse cranes handling turbine-generator components.

b. The design team should prepare detailed equipment arrangement drawings for new crane and hoist procurements and equipment rehabilitation contracts, for the purpose of receiving detailed as-built drawings of the crane/hoist for future project maintenance work activities. The drawings should include a general layout of the crane/hoist machinery arrangement with desired features fully detailed (such as conceptual design with sufficient detail to show general equipment arrangements and interfaces with site specific features, working clearances, and minimum personnel access requirements).

20–11. Crane, Hoist, and Load Handling Equipment Design Criteria

a. General.

(1) Design criteria for hydropower cranes and hoists is covered in the following paragraphs. However, detailed design criteria are provided in the crane guide specifications discussed in paragraph 20–9. EM 1110-2-2610 provides a thorough discussion on mechanical components and design criteria appropriate for both electromechanical and combination hydraulic-mechanical systems used to operate navigational locks and spillway/dam gates. EM 1110-2-2610 should also be considered applicable to hydropower cranes and hoists.

(2) The crane/hoist rated capacity must be based on the results from the load demand analysis and assessment discussed in paragraph 20–7. For hydraulic hoists, the rated capacity load is the rated hydraulic actuator pressure.

b. Design Criteria, Structural.

(1) For standard commercially available cranes, hoists, and LHE, follow applicable industry standards and manufacturer’s recommendations. For custom designed cranes and hoists, such as intake/draft tube gantries or most powerhouse bridge cranes, structural design criteria must be specified in contract documents identifying all critical design criteria such as loads, load combinations, allowable stresses or allowable strengths, and stability criteria. Where multiple codes and standards are used to develop design criteria, a technical analysis is required. Crane designs should follow a consistent approach throughout. The Designer of Record is responsible to ensure that design meets minimum USACE and industry standards.

(2) Structural crane design criteria historically have not been consistent throughout the industry. There are a variety of differing sources to evaluate. Crane loads, the load combinations, and the allowable stress or strength criteria used to design the crane structure must be developed with a clear, logical, and consistent approach in terms of

reliability and safety. The design approach of each standard should be considered as a system when drawing from multiple sources. Simply taking the most conservative of the aggregated applicable standards is likely to result in an overly conservative crane design that may be too heavy for the structures supporting the crane. Conversely, selecting isolated criteria (also called “cherry picking”) from one standard for use with a different standard may result in a design that is not conservative.

(3) The HDC has developed a system of design criteria for hydropower cranes based on evaluation of USACE historic crane design criteria and current applicable industry standards.

(a) In this system, cranes are designed for dead loads, hoisting loads, travel loads, vertical impact, operating wind load of 10 pounds per square foot (psf) (479 Pascals [Pa]), storage wind load of 40 psf (1915 Pa), horizontal inertial (or tractive) forces limited to between 5 and 10 percent of the sum of the travel and dead loads of the trolley or gantry, and the maximum motor torque (MMT) of the hoist.

(b) Load combinations are divided into: Category I for normal operating conditions; Category II for unusual operating conditions such as collision and extreme wind when the crane is stored; Category III for extreme operating conditions such as an MMT event or extreme wind during hoisting. Example sketches of each category load case can be found at the end of this chapter (see Figure 20–13, Figure 20–14, and Figure 20–15). In addition to these examples, the trolley should be checked at each slot location plus at extreme ends of trolley rails. The load combinations in the gantry travel direction are identical to the trolley travel direction shown in the examples, except oriented 90 degrees from one another.

(c) Structural components of the crane are designed per the American Institute of Steel Construction (AISC) 325 allowable strength design methodology and are not to exceed 75 percent of AISC 325 allowable strengths for Category I, 100 percent of AISC 325 for Category II, and 90 percent of the nominal strength as defined by AISC 325 except columns (legs) are limited to 100 percent of AISC 325 for Category III.

(d) For crane stability, the safety factor against overturning (a ratio of the righting moments divided by the overturning moments) is required to be 1.25 for all load combinations.

(4) The system (described above) of loads, load combinations, and allowable strengths is the recommended starting point for developing structural design criteria for custom USACE hydropower cranes. Site restrictions, changing standards, and unique crane functions require that crane design criteria be updated and tailored for the specific application.

(a) There are industry standards that support calculation of inertial/tractive forces less than 10 percent. If lower tractive forces are used, calculations must be provided to support the lower value. Additionally, with lower traction forces, seismic loads should be considered.

(b) It is acceptable to use ASCE 7 to calculate site-specific wind loads for cranes. However, the designer/specifier is cautioned to be aware of differing definitions for applied wind area included in the crane specifications and of implicit load factors included the ASCE 7 wind tables, which may overstate the impact of wind loads. This may, in turn, lead to a heavier crane and larger crane wheel loads that exceed the capacity of the crane runway support structure.

(5) Other considerations are as follows:

(a) Accurately documenting crane self-weight may require weighing an existing crane during the design phase of a rehabilitation project.

(b) The structural capacity of the crane runway support structure may be different when the crane is positioned over a gate slot (stationary) versus during travel along the powerhouse deck that can result in a crane with different hoisting and traveling rated loads.

(c) When designing cranes with trolleys, the trolleys must be placed in the position that causes worst loading condition on the crane structure.

c. Design Criteria, Mechanical.

(1) For standard commercially available cranes, hoists, and other LHE, follow applicable industry standards and manufacturer's recommendations.

(2) For custom designed cranes and hoists, such as intake/draft tube gantries or most powerhouse bridge cranes, mechanical design criteria must be specified in contract documents identifying all critical design criteria such as allowable stresses, application factors for gears and gearboxes, CMAA factors for crane wheel sizing, and shock and fatigue factors for shafting. The list of crane guide specifications for custom designed cranes discussed in paragraph 20–9 include the complete details of design criteria for mechanical components. The following paragraphs offer a sample of mechanical design criteria from those specifications.

(3) Where multiple codes and standards are used to develop design criteria, a technical analysis is required. Crane designs should follow a consistent approach throughout. The Designer of Record is responsible to ensure that design meets minimum USACE and industry standards.

(4) Mechanical parts should be designed for the rated capacity load with a minimum factor of safety (FS) of 5 based on the ultimate strength of the materials. In addition, mechanical components should be designed to withstand the forces produced by hoist motor-stalled torque or MMT as limited by VFD controls (when VFDs are used), with resultant stresses that do not exceed 75 percent of yield point of the materials involved. Where original equipment manufacturer (OEM) products are specified and published rating data is available, the designer should use caution in blindly applying factors of safety to OEM components that already have inherent service factors provided for in their design. This is to avoid having the designer grossly oversize a component through the application of safety factors on safety factors.

(5) In determining the size of hoisting ropes, the maximum rope tension resulting from the rated capacity load should be used and should consider the overall efficiency of the hoist tackle in the blocks and other parts. The resulting rope tension should not be greater than 1/5 the nominal breaking strength of the rope. In addition, the rope tension resulting from the (locked rotor torque or MMT as limited by VFD controls) must not exceed maximum torque of the motor 0.7 of the nominal breaking strength of the rope.

(6) Additional discussion on wire rope selection criteria is in EM 1110-2-3200 and the most recent edition of the Wire Rope User's Manual. ASME B30.30 includes provisions that apply to the construction, selection, installation, attachment, testing, inspection, maintenance, and replacement of wire rope. ASME B30 safety standards should also be reviewed as they are typically updated more frequently than EMs.

(7) The machinery efficiencies used for calculating the hoist and travel drive component sizing must not exceed the values provided in CMAA 70. Machinery efficiency for grease-lubricated gearing must be reduced by 0.02.

(8) Gears for enclosed speed reducers should be of the spur or helical type and designed according to AGMA 2001. Bevel-type gears are designed according to AGMA 2003. Overhung gears or pinions should not be used except for bevel and spiral bevel pinions that are internal to travel speed reducers.

(a) For design of gearing inside custom speed reducers and open gearing, the pitting resistance power rating of gears must not be less than the motor horsepower times 0.8, and the bending strength rating of gears must not be less than the motor horsepower times 1.0. Conservative values should be used for AGMA rating factors (such as overload factor, safety factor for pitting, safety factor for bending strength). A value of 1.0 should be used for stress cycle factor for pitting resistance and stress cycle factor for bending strength, which provides a conservative design for gear rating. A value of 70 percent of the allowable bending stress number must be used for the gantry drives and for any idler gears or other gears that are subject to reverse loading.

(b) The rating of commercial speed reducers must be based on the catalog rating of the speed reducer, with the rating being equal to or exceeding the maximum input power times an application factor of 1.50. A value of 70 percent of the catalog rating must be used for reducers for the gantry, bridge, trolley drives, and other locations that are subject to reverse loading.

(9) Hoist drums should be designed with double-diaphragm construction on each end of the shell (except for barrel coupling connection between drum and speed reducer, which typically uses single thick drum end diaphragm plate). Although they were commonly used on older designs, spoked ends with one side unsupported (such as single-diaphragm design) must not be used on new or rehabilitated cranes. Drums must be designed for combined bending and crushing stress at rated load, and comply with paragraph 20–11c(4) and CMAA 70, using the more conservative factors for allowable combined stresses. Drum buckling/crushing calculations are done per Roark’s Formulas for Stress and Strain equations and the minimum bucking safety factor must be 2.

(10) Direct-drive of the hoist drum by a barrel coupling between drum and speed reducer is strongly preferred to open gearing due to alignment, quality, maintenance benefits, and reduction in risks related to gear separation forces. There are cases, such as a rehabilitation with limited space or large capacity hoists (typically greater than 150 ton), where direct-drive is not feasible and a hoist must have open gearing. The pillow block bearings for shafting supporting open gearing must have shear blocks or other means designed to prevent gear separation under maximum loading. See Figure 20–6 for general arrangement of a hoist with direct-drive and a hoist with open gearing final reduction.

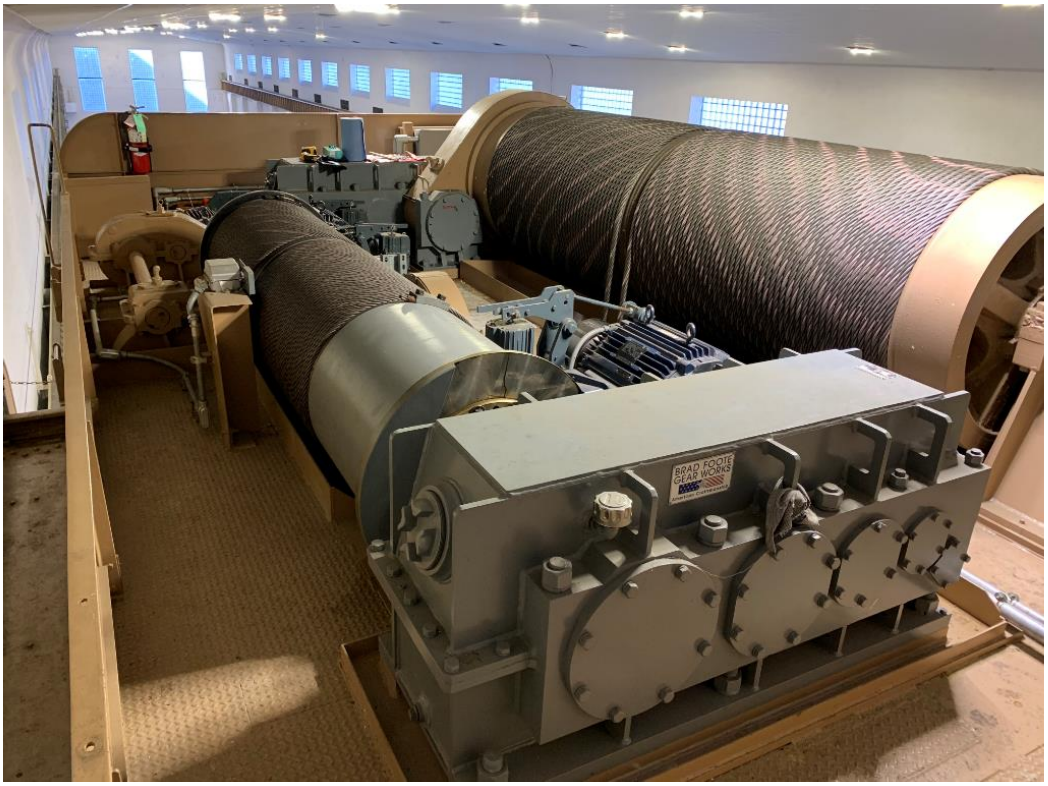


Figure 20–6. Hoist with direct-drive in foreground; hoist with open gearing final reduction in background

(11) For hoist open gears, there may be benefits to considering double helical gears. They are more expensive than spur gears but have a more favorable failure mode due to their higher gear tooth contact ratio. If a single helical gear is used, take special care to address thrust loading. Spur gears, however, are acceptable with quality control checkpoints on gear material and heat treatment. Spur gears also require proper lubrication and maintenance intervals.

(12) Gantry and bridge drive machinery should be designed with such capacity that the movement of the structure is steady, with a minimum of vibration or racking while moving at rated speed with maximum travel load. For outdoor cranes, this includes travel against a wind pressure of 5 psf (239 Pa) of exposed surface of the crane. The capacity of the gantry/bridge travel motors must be sufficient to provide the specified performance without exceeding the full-load torque. The tractive effort provided to overcome the rolling friction of the wheels and mechanical losses of the drive must be a minimum of 15 pounds per ton. Typically, no less than 25 percent of the wheels on each rail should be connected for driving. Additional design considerations are as follows:

(a) CMAA 70 provides a figure that shows the various bridge/gantry drive arrangements that cover most four- and eight-wheel crane drives. The figure in CMAA 70 shows arrangements for A1, A2, A3, A4, A5, and A6 drive arrangements.

(b) Gantry drives are typically CMAA A4 drive arrangements with shaft mounted gearmotors mounted on corner drive trucks (see Figure 20–7). The motor(s) on each side of the crane should be designed and rated to drive 2/3 of the crane rated capacity

load, due to potentially unsymmetric location of the load during gantry travel. In computing the loads on an A4 drive arrangement, 100 percent of the motor torque should be considered as applied to the drive machinery (such as axles/shafts, gears, keys). Flat-tread drive wheels are used for gantry cranes with A4 drive arrangements.

Figure 20–7. Powerhouse gantry crane with Crane Manufacturers Association of America A4 drive arrangement

(c) Bridge drives with CMAA A1 (Figure 20–8), A2, A3 (Figure 20–9) and A5 drive arrangements have a single motor located near the center of the bridge and connected to a self-contained gear reduction unit, also located near the center of the bridge. Cross shafts joined by couplings and supported by bearings are used to drive each end of the crane. CMAA A2, A3, and A5 drive arrangements include additional gear reductions located near each drive truck, or gears pressed and keyed on the axles of the truck wheels in the case of an A2 arrangement. The motor for A1/A2/A3/A5 drive arrangements should be designed and rated for 100 percent of crane rated capacity load, and 2/3 of the motor torque should be considered as applied to each side of the drive when computing loads on the drive machinery. Taper-tread drive wheels are required for bridge drives with A1/A2/A3/A5 drive arrangements. Idler wheels are typically flat tread.

Figure 20–8. Powerhouse bridge crane with Crane Manufacturers Association of America A1 drive arrangement

Figure 20–9. Powerhouse bridge crane with Crane Manufacturers Association of America A3 drive arrangement with all gear reduction located at each drive truck; gear reducer is partially visible in right image

(d) Bridge drives with CMAA A4 drive arrangements are designed similar to gantry drives with A4 drive arrangements, except there may be two variations of drive machinery configurations. Both variations locate the motors near each end of the bridge. The Type 1 variation of this drive arrangement (see Figure 20–10) includes a motor connected to a self-contained high-speed gearbox. The high-speed gearbox is connected via short shafting and couplings to secondary (low-speed) gear reduction. The low-speed gear reduction drives the truck wheels through gears pressed and keyed on their axles or by gears fastened to the truck wheels, and with pinions mounted on the end section on the shaft. Type 2 variation of this drive arrangement (see Figure 20–11) includes a motor connected to a self-contained gear reduction unit that direct-drives the wheel axle shaft extension. For both types, the driven wheels must be flat tread.

(e) Existing powerhouse bridge cranes with CMAA A1/A2/A3/A5 drive arrangements that are being rehabilitated should retain the original designed drive arrangement configuration for proper skew correction and tracking performance. Some existing USACE powerhouse bridge cranes that have been converted from A1/A2/A3/A5 drive arrangements to A4 arrangements have performed poorly and developed skewing and tracking issues, resulting in severe wheel flange and rail wear.

Figure 20–10. Powerhouse bridge crane with Crane Manufacturers Association of America A4 Type 1 drive arrangement

Figure 20–11. Powerhouse bridge crane with Crane Manufacturers Association of America A4 Type 2 drive arrangement

d. Design Criteria, Mechanical – Cranes/Hoists Used for Emergency Closure. Specifying a rated capacity for an emergency closure system that includes all conceivable load cases may be determined to be infeasible or unnecessary due to site-specific conditions and risk assessment. In these cases, engineering judgment may be used to support the design of a crane or intake hoist whose nominal rated capacity is less than the anticipated maximum downpull forces, but which, because of its standard safety factor, still has the capacity to safely accommodate those downpull forces at an alternate, but appropriate, factor of safety. In all such situations, the HDC should work with the District case-by-case to determine the best technical and cost-effective solution. While the specifics of these situations vary, the following bounding conditions can be considered a prudent starting point in design.

(1) Highest overload case’s unit stresses must not exceed 75 percent of the yield strength of the material, and wire rope loads must not exceed 70 percent of the nominal breaking strength.

(2) Documentation of assumptions and a thorough narrative of the PDT’s rationale behind the final hoist rating determination must be part of the design records.

(3) Sizing a crane rated capacity for maximum hydraulic downpull can result in a heavier, more expensive crane, and should be factored into the selection of the crane rated capacity. The designer should evaluate if a heavier crane operating with maximum travel loads can safely operate along the entire length of the intake deck without

exceeding deck load limitations. Some powerhouses have different maximum wheel load limits at different locations along the length of the crane rails.

e. Design Criteria, Electrical.

(1) *Systems and Components*. Electrical systems and components of cranes and hoists should be industry standard equipment whenever possible. They should be designed and installed to conform to modern crane standards. CMAA 70, ASME B30.2, NEMA ICS 8, and NFPA 70 Article 610 are specifically for cranes and hoists and should be used for design requirements and guidance.

(2) *Control Systems*. Control systems should include solid-state controls, VFD, or adjustable speed drives (ASD)wherever possible. This allows maximum control of hoisting and motion speeds and additional built-in safety features such as brake slip and holding detection, high hook load detection and warning, and torque control limits.

(a) Static control systems should be used for hoists, use encoder feedback (closed loop, flux vector control) to verify proper operation of brakes and motors, and correspond with operator direction.

(b) Static control systems for travel functions should use open loop flux vector control or V/Hz, especially if there are multiple drives and/or motors associated with a travel function.

(c) PLCs should be used for complex cranes or functions of cranes, but is not recommended and should not be required for most simple cranes.

(d) Hoist motors and feeder cables should be rated for continuous duty to account for very long, slow hoisting and lowering operations where motor speed prevents the ability to provide adequate air circulation for cooling.

(e) Relay-based controls (such as wound rotor or dual winding motors) are allowable when fine control and feedback is not required. They are also allowable where cost, scale, and simplicity of the system are major factors.

(3) *Motor Insulation and Temperature Rise*. Per NEMA MG 1, motor insulation and temperature rise should be coordinated to ensure temperature limits are not exceeded during long-time, slow-speed operation. Include motor embedded and motor thermal protection devices in motor windings.

(4) *Hoist Control Braking*. New designs are typically supplied with VFDs that provide a controlled braking means when lowering the hoist load; this is done via dynamic braking units (DBUs) as part of the hoist VFD controls. Dynamic braking is a method of using motors as generators when slowing a movement. The electrical load on the motor, when operated as a generator, is routed via the DBU to resistor banks.

(5) *Hoist Holding Brakes*. There are several factors that are considered when designing hoist holding brake requirements. For new designs, each hoist should have two holding brakes (see exceptions below). For existing equipment, spatial constraints may not physically allow the installation of two brakes.

(a) Each hoist should have two holding brakes, and at least one of the brakes must be mounted on the gearbox input shaft (preferably both mounted on the input shaft, one on each side of the reducer, see Figure 20–12). There should be a one to three second time delay between the primary and secondary brake. The time delay should be functional during normal hoisting and emergency stop operations (like when power is removed from the crane/hoist). Each brake must be rated not less than 125 percent rated motor torque and the brake holding torque set at 125 percent full load motor

torque. Brake ratings, dimensions, and performance requirements must conform to NEMA ICS 8 and Association of Iron and Steel Engineers Technical Report Number 11.

(b) For existing equipment, spatial constraints may not physically allow installation of two brakes. In this case, a single holding brake may be used for a hoist, with a rating of not less than 150 percent rated motor torque and the brake holding torque set at 150 percent full load motor torque. The brake must be mounted on the gear reducer input shaft. Some examples of one holding brake include draft tube gantry cranes, intake gate fixed hoists, and small capacity hoists (such as latching hoists, actuating hoists). Hoists with mechanical load brakes may also only have one holding brake, rated not less than 150 percent rated motor torque and the brake holding torque set at 150 percent full load motor torque (load brake hoists are typically not VFD controlled, and thus rely on the load brake for controlled braking during lowering).

(c) Brake wheel couplings should not be used because the grease in the coupling can leak from the coupling seal and contaminate the brake wheel and pads which compromises the brake's ability to stop and hold the load. This usually requires most commercial or custom gear reducers to be supplied with extended input shafts to mount the brake wheel plus space to install a flexible coupling between the reducer input shaft and motor shaft.

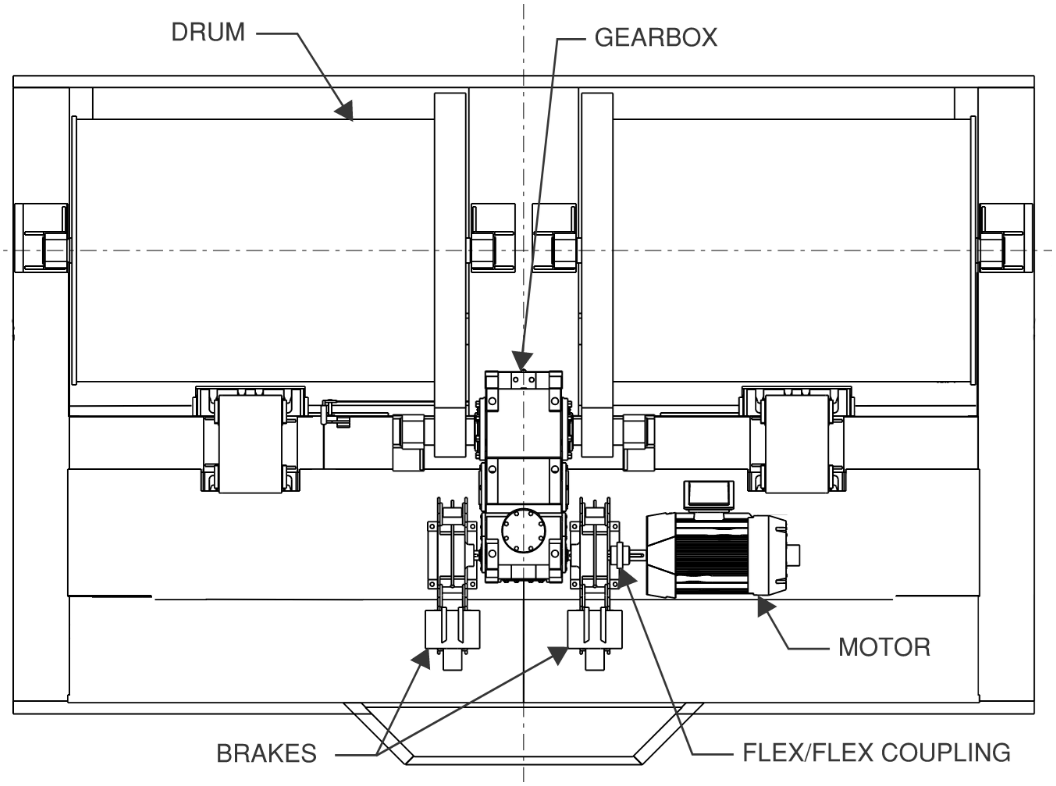


Figure 20–12. Hoist arrangement with two holding brakes; each mounted on the gearbox input shaft

(6) *Travel Brakes*. Each travel drive must have one holding brake, typically mounted on the motor shaft. Each brake should be rated not less than 100 percent full load motor torque, except in applications where commercial brake sizes do not offer adjustable brake torque settings to exactly match the motor full load torque. In this case, the engineer should evaluate whether brake torque can be set to between 80 to 100 percent motor full load torque. Trolleys subject to horizontal loading during hoisting operations (such as trash raking operations) should have brakes sized and brake torque set such that the trolley does not move due to horizontal loading.

20–12. Welding Standards for Load Handling Equipment

a. For standard commercially available cranes and LHE, follow applicable industry standards and manufacturer's recommendations. For custom designed cranes and hoists, such as intake/draft tube gantries or most powerhouse bridge cranes, fabricate according to American Welding Society (AWS) D14.1 or AWS D1.1. One consistent approach (AWS D1.1 or AWS D14.1, not both) should be used throughout fabrication. Specific requirements, as stated below, must be met when procuring custom designed cranes/hoists/LHE to assure safe and reliable quality of fabrication when following either AWS D14.1 or AWS D1.1 welding standard.

b. AWS D14.1 has different requirements for primary and secondary welds. AWS D14.1 requires primary welds to meet stringent quality inspection criteria equal to AWS D1.1 criteria for cyclic loads in tension. In AWS D14.1, a weld is classified as a primary weld if the failure of the weld would result in a carried load being dropped more than four inches or an increase in stress beyond the allowable limit. Making this determination requires detailed analysis and possible testing. For these reasons, crane designers and Government reviewers must be trained, knowledgeable, and experienced in determining which welds are primary welds.

c. In AWS D14.1, secondary welds receive only NDE inspection as required by owner. Any welds not specifically identified as primary welds are treated as secondary welds. Specifiers must require that all primary welds be clearly identified on the fabrication drawings and 100 percent of primary welds be inspected using NDE methods. Specifiers should require that a percentage of secondary welds receive inspection.

d. AWS D1.1 is a comprehensive, broadly applicable structural steel welding standard and does not differentiate between primary and secondary welds. When using AWS D1.1 for crane and other LHE fabrication, specifiers must define which welds are to be inspected and to which requirements within the standard. For cranes and hoists, this should include 100 percent visual inspection for all welds, plus more detailed NDE for a predefined percentage (25–100 percent) of the welds on all primary load-carrying members.

e. Specifiers must define primary load-carrying members as those carrying principal loads (for example: the gantry frame, trolley, and lifting beam) and must require welds for these members be inspected to the quality requirements for cyclic loads in tension per AWS D1.1. Specifiers should also require welds connecting ancillary items to primary load carrying members be held to the same quality standards as welds for primary load carrying members. Taken together, these requirements are more stringent than simply following the requirements of AWS D14.1 and are recommended for long-term service reliability.

20–13. Acquisition Strategies for Hydropower Cranes and Hoists

a. As with most specialty work, experience has shown that the most successful crane and hoist contracts, with minimal cost/schedule impacts, are ones that are performed by highly qualified crane manufacturers with experience designing and fabricating custom crane and hoist machinery. The HDC and partner district should work together to develop the acquisition strategy for the specific job that considers contracting and acquisition regulations as well as the technical requirements and lessons learned from past work. On request, HDC can provide examples of past acquisition strategies that have been successful.

b. Even if the powerhouse design engineer has the technical skills and knowledge to complete the design, experience has determined that this approach is not the most cost-efficient way to complete the design. By not specifying exact equipment, the contractor is allowed flexibility in procurement, resulting in a lower overall cost and lower risk to the Government. Furthermore, a design that is complete and absolute requires selecting specific components, as each individual component must be sized, located, and adjusted to work with the integrated system. Selecting specific components requires sole-source justification, which stifles innovation and the best value to the Government and contractor.

c. *Design Team Support for Procurement*. Crane contracts have historically been pursued by underqualified contractors, leading to quality and performance issues. Involving the design team per ER 10-1-53 during advertisement and award can help preclude some of these issues.

20–14. Powerhouse Bridge Cranes

a. *General*.

(1) Detail design criteria for powerhouse cranes is covered in paragraphs 20–9 and 20–11. For outdoor powerhouses, the powerhouse crane is normally a gantry type.

(2) Coverage herein is limited to additional general factors regarding crane requirements and crane selection. The discussion is applicable particularly to powerhouses with conventional vertical units; however, most factors noted are also applicable to cranes servicing slant axis or bulb units.

(3) Some slant axis units may require two cranes, one upstream and one downstream, because of horizontal distance between generator and turbine. Special intermediate lift and handling facilities are usually involved with either slant- or bulb-type units. These special facilities should be determined and furnished by the generator and turbine contractors subject to the normal design office shop-drawing reviews.

b. *Number of Cranes*. The choice of providing one or two cranes is an important consideration in powerhouses with several units or heavy capacity requirements. Factors entering into this determination are:

(1) *Procurement Cost*. This cost considers one crane versus two.

(2) *Powerhouse Structural Costs*. A single crane may increase structural costs because of greater physical size, though generally only moderate additional cost is involved.

(3) *Construction and Erection Advantages of Two-Crane Availability*. Two cranes are usually more beneficial in long multi-unit powerhouses and may have significant advantages where the construction schedule requires continued erection work after several units are in operation.

(4) *Additional Crane Clearance*. The necessity to provide two-crane lifting beam configuration increases the roof height.

(5) *Hook Coverage Limitations*. Unusually large capacity single cranes result in greater floor areas not accessible to a lifting hook.

(6) *Additional Maintenance Cost*. Maintaining two cranes has a higher maintenance cost than maintaining a single crane.

(7) *Value of Unit Downtime*. Two cranes may expedite maintenance or repairs of powerhouse turbine-generator equipment.

(8) *Bulb or Slant Axis Units*. For bulb or slant axis units, seldom are two cranes justified in powerhouses with less than five units. For five or more units, the design memoranda should include the considerations pertinent to selecting one or two cranes.

c. *Crane Capacity*. Determine capacity of the powerhouse crane(s) according to load demand analysis and assessment discussed in paragraph 20–7 and the following:

(1) The crane capacity is considered the sum of the rated capacities of the main hoists. On cranes with two main hoists, the weight of the lifting beam needs to be included as part of the load in determining the required capacity. Similarly, for an installation using two cranes with two main hoists per crane, the estimated weight of the three lifting beams is a part of the load. Actual computed weights of the generator rotor, turbine, shafts, and lifting devices are normally available prior to the date scheduled for procuring the crane, thus permitting accurate final determination of maximum crane loads.

(2) When procuring cranes for new powerhouses, numerous factors beyond engineering control tend to disrupt orderly scheduling. It is frequently necessary to prepare contract drawings and specifications for cranes before accurate final loads are determined. It is also sometimes necessary to firm up powerhouse structure design affected by crane capacity and clearances prior to final confirmation of lifting loads. In such cases, capacity should be based conservatively on estimated loads (to avoid later increases).

(3) Loadings due to planned or potential future units should also receive consideration in determining crane capacity and be included in the design computations.

(4) All new powerhouse cranes must be rated for the maximum load expected. Consideration must be made for increased weights of turbine generator components during unit uprating.

(5) All refurbished powerhouse cranes must be uprated (if possible) for the maximum load expected. If uprating is not feasible, consider replacing the crane.

(a) Historically, during the original dam construction years, it was USACE practice to specify crane ratings that allow up to 10 percent overload for infrequent special heavy lifts, such as the generator rotor, when a preferred crane rating falls within this range. For cranes that were designed according to USACE guide specifications, this overload was well within the allowable stresses permitted by the CMAA standards and was consistent with ANSI/ASME standards and OSHA’s interpretation of their regulations.

For example, it was common practice and allowed by OSHA and ASME B30.2 to perform infrequent lifts up to 110 percent of the crane rated capacity. This practice is no longer permitted by B30.2 since any lift greater than rated capacity now requires a planned engineered lift.

(b) If cranes are expected to see more than two lifts exceeding the rated capacity, in a 12-month span, then a planned engineered lift with calculation review of the design per ASME B30.2 is required. Where crane manufacturers for existing cranes are no longer in business to support the calculations review, USACE personnel with crane design experience may serve as the qualified person to review the crane design and supporting structure for developing the planned engineered lift documents.

(c) See Chapters 5 and 6 for additional discussion on when to uprate (or replace) powerhouse cranes. This is to ensure powerhouse cranes are not the constraining factor on turbine and generator size or weight, and turbine-generator weights/dimensions considerations when evaluating powerhouse crane coverage/clearances.

d. *Controls*.

(1) The crane industry has shifted from DC drive and wound rotor AC systems to AC VFD systems. VFD drives, in addition to being the standard design for crane manufacturers, provide safety features not available on previous generations of crane controls. Failsafe VFD drive systems should be used on both crane rehabilitations and new installations. VFD drives for hoist applications should operate using closed loop, flux vector control scheme with encoder feedback to control and monitor hoist movement.

(2) Holding brakes should be either DC magnetic or AC thruster, spring set, shoe type (for hoists) or motor-mounted friction disc type (for travel functions).

(3) Radio remote control is an option that is commercially available and should be considered to supplement cab controls.

(4) Load cell feedback for hoists is recommended, with care to avoid nuisance trips triggered as the load cell undergoes hysteresis or goes out of calibration. For hoists with multiple parts of wire rope, sheave and wire rope friction may affect the accuracy of the load seen at the load cell location. Load cell readouts are required for trash raking hoists and auxiliary hoists that have inherent uncertainty and variation in loading. Load cell readouts are recommended but not required for main hoists on permanently installed hydropower cranes that were designed to pick specific equipment as a known load.

(5) For additional guidance on crane control design, see CMAA 70 and ASME B30.2.

e. *Appearance*. Powerhouse bridge crane appearance should be consistent with the interior finish of the powerhouse. It is usually advisable to rely on the powerhouse architect to determine an acceptable appearance, but compromises are necessary where preferred appearance impairs maintenance, full utility, or safety.

f. *Access*.

(1) In the early stages of powerhouse layout, convenient and safe access to bridge cranes should be considered. In larger powerhouses, the vertical distance from erection areas to the crane cab level may be 50 ft (15 m) or more. This makes it desirable to provide access from a level served by an elevator when practicable.

(2) Access via convenient stairs is preferred when elevator service is impracticable, but the most common access of original installed equipment, particularly in the smaller powerhouses, is via fixed ladders. When the crane is being replaced or rehabilitated, stairs should be provided in lieu of fixed ladders for accessing the upper levels of the crane, for ease of personnel access. Fixed ladders, where used, that exceed 20 ft (6 m) in length require a ladder-climbing device (LCD).

(3) Direct access to the cab elevation using stairs or a fixed ladder is preferred. Access to the cab via corbel, bridge, and ladder descent into cab is the least desirable means of access but is acceptable when required by powerhouse arrangement.

(4) The crane "parking" location should be reasonably close to the principal crane use area. Safety is the first consideration in crane access, and architectural emphasis should not be at the expense of either safety or convenience.

20–15. Powerhouse Gantry Cranes

a. General. General considerations noted in paragraph 20–14a are applicable. Powerhouse cranes of the gantry type are usually limited to outdoor powerhouses. In the case of an indoor powerhouse such as Libby Dam in Montana with construction making it impractical to support bridge crane rails, a gantry or semi-gantry may be required. There has been very limited application for such cranes in USACE projects, but data on the Libby crane is available from the HDC, for reference purposes. The design generally should follow applicable criteria for outdoor powerhouse gantries.

b. Number of Cranes. More than one gantry crane is seldom justified since cost and bulkiness tend to offset the advantages. Portable equipment can usually be used for minor work at outdoor powerhouses, further diminishing the value of a second crane.

c. Crane Capacity. Statements in paragraph 20–14c apply. In cases where additional hoists are provided serving the functions of intake gantry cranes or draft tube gantry cranes, capacity of those hoists should be as described in paragraphs 20–16 and 20–17, respectively.

d. Controls. Paragraph 20–14d powerhouse bridge crane controls apply to powerhouse gantry cranes.

e. Appearance. Comments in paragraph 20–14e apply.

f. Access. Paragraph 20–16g intake gantry crane access recommendations apply to powerhouse gantry cranes.

20–16. Intake Gantry Cranes

a. General.

(1) The powerhouse intake gantry crane may be used as a dual-purpose, powerhouse intake-spillway crane but is more commonly restricted to powerhouse intake service. Other "specialty" intake gantry cranes include trash raking cranes, fishway cranes, and fish screen handling cranes. Intake deck-hoisting requirements vary widely between projects and good judgment is required to select the optimum provisions for each crane.

(2) Coverage here includes general factors pertinent to the selection and type of equipment. See paragraphs 20–9 and 20–11 for discussion on detailed design criteria for cranes.

b. *Intake Gantry Lifting Functions.*

(1) *Intake Gates and Bulkheads*.

(a) The heaviest lifts normally involve handling the intake gates and bulkheads. Trolley-mounted hoists permit handling of the gates and bulkheads with the same hoist. Routine raising and lowering, gate cracking for unit re-watering, maintenance support, and transfer to storage slots or other repair locations are normal requirements.

(b) In some instances, the crane is used during gate delivery and erection; however, construction scheduling usually requires contractor cranes being available for gate erection.

(c) Intake gantry cranes should not be used to lower intake gates in an emergency because of the slow response in addition to the potential load capacity problems resulting from gate hydraulic downpull. See paragraph 20–2 for additional discussion.

(2) *Fish Guidance Equipment*. Raising and lowering fish guidance equipment, such as submerged traveling screens or submerged bar screens and vertical barrier screens, is a major task for intake gantry cranes at some powerhouses. Additional provisions are needed to handle fish guidance equipment, such as tugger hoists, an auxiliary hoist, faster main hoist speeds, and additional lifting devices. Careful planning is needed to assure all needed provisions are included in the crane design.

(3) *Trash Rack Service*. Raising and lowering trash rack sections and raking trash racks are common intake gantry crane functions where distances from gate and bulkhead slots to trash racks are moderate. For wider decks, using a standard commercially available rake and hoist unit or a separate trash-raking crane is more practical.

(4) *Handling Individual Gate Hoists*. Where individual gate hoists are provided, placement and removal are normally an intake gantry crane function. The clearances for wire rope, fixed-hoist machinery and hydraulic cylinders; load transfer supports; and procedures for raising and lowering cylinders between vertical and horizontal positions require careful planning.

(5) *Transformer Handling*. Where main power transformers located on intake decks are within the crane load rating otherwise required, loading and unloading of the transformers is a common crane function. Increasing crane capacity, hook coverage, or number of hoists for transformer handling alone is seldom justified as temporary facilities are practical for the infrequent movements.

(6) *Loading and Unloading Rail Cars and Trucks*. Intake decks are usually accessible to trucks and, in some cases, rail cars. Crane clearances and hook coverage should provide convenient handling.

(7) *Miscellaneous Lifts*. As applicable, miscellaneous lifts should also be considered in crane design. Lighter lifts may be made using mobile cranes, but availability, accurate control, and safety usually favor using an intake gantry crane.

c. *Number of Cranes*. More than one intake gantry crane is seldom justified, except for powerhouses that use a dedicated intake crane for emergency closure, where a second intake gantry crane is recommended for normal maintenance activities. Powerhouses with many units may also have a second intake gantry crane for specialty services (such as trash raking or fish screen handling).

d. *Crane Capacity*. Crane capacity should be determined based on the load demand analysis and assessment from paragraph 20–7 *e.* *Controls*. Per paragraph 20–14d, powerhouse bridge crane controls are applicable to intake gantry cranes.

f. *Appearance*. Intake gantry crane appearance should be consistent with the intake deck area of the powerhouse. It is advisable to rely on the powerhouse architect for determination of an acceptable appearance, but compromises are necessary where preferred appearance impairs maintenance, full utility, or safety.

g. *Access*. Stairs should be provided in lieu of fixed ladders for accessing the upper levels of the gantry crane for ease of personnel access. Fixed ladders, where used, that exceed 20 ft (6 m) in length require an LCD.

h. *Dual-Purpose Cranes*. Using the intake gantry for both intake deck and spillway deck functions should be considered where usage for routine operational purposes is not required on either deck. Obtain agreement from the operations division involved on the acceptability of a dual-purpose crane.

20–17. Draft Tube Gantry Cranes

a. *General*.

(1) The principal function of a draft tube gantry crane is to handle the draft tube bulkheads. Alternate provisions are sometimes practical and should be considered. This includes using a monorail hoist where deck configuration and slot location are unsuitable for a gantry or a mobile crane, or where there are only one to three units. Then the project should have a mobile crane available full time for other purposes.

(2) Commercial monorail hoists are generally available up to 10-ton (9.1-tonne) capacity. Mobile cranes are less desirable for operating convenience and safety reasons, so procuring a mobile crane specifically for handling draft tube bulkheads is not recommended. See paragraphs 20–9 and 20–11 for discussion on detail design criteria for cranes.

b. *Lifting Functions.* Draft tube cranes typically perform the following functions:

(1) Draft tube bulkheads. This function usually determines the crane rating.

(2) Deck slot and hatch covers.

(3) Fish facility equipment. At projects where fish facilities are incorporated into the draft tube structure, the draft tube crane may be required to handle gates, bulkheads, stoplogs, machinery, weirs, diffusers, etc.

c. *Number of Cranes*. One draft tube gantry will provide all required service.

d. *Crane Capacity*. The rated capacity of the crane should be specified the same as that of the hoist, and is the load that the crane is designed to handle while meeting the design criteria defined in paragraph 20–11.

e. *Controls*. Paragraph 20–14d powerhouse bridge crane controls are applicable to draft tube gantry cranes.

f. *Appearance*. Draft tube crane appearance should be consistent with the tailrace area of the powerhouse. It is advisable to rely on the powerhouse architect for determination of an acceptable appearance, but compromises are necessary where preferred appearance impairs maintenance, full utility, or safety.

g. *Access*. Paragraph 20–16 intake gantry crane access recommendations apply to draft tube gantry cranes.

h. *Trolley*. For draft tube bulkhead service alone, a gantry crane with fixed hoist is adequate. If another service such as fish facility handling is required, then a trolley-mounted hoist may be justified.

20–18. Mobile Cranes

Mobile cranes are seldom furnished specifically for the powerhouse since they are normally an item of general project equipment. They are usually specified to match an existing, commercially available item. The powerhouse design should consider which powerhouse lifts will be handled with a mobile crane, the loads, and required hook travels and boom lengths. Special slings, lifting beams, and lifting eyes to achieve required safety factors are usually provided for each type of lift. Review EM 385-1-1 for requirements on mobile crane usage and associated load placement plans.

20–19. Maintenance Shop Bridge Cranes

a. *General*.

(1) All required lifting and transporting operations in the maintenance shop can be accomplished with an economical floor crane plus a minimum of temporary rigging. The provision of the more costly bridge crane requires considerable justification. Since a bridge crane can expedite handling, the potential for a heavy volume of essential work in the shop at one time is the principal justification.

(2) For powerhouse maintenance work, ten or more main units along with a fully equipped shop, usually justifies a bridge crane in the maintenance shop. See paragraph 20–11 for design criteria for bridge cranes.

b. *Crane Characteristics*. The crane should be kept as simple as practical, avoiding the more sophisticated control options and writing the specifications around generally available catalog equipment. Single-speed hoist control in the range of 12–18 fpm (0.06–0.09 m/s) is satisfactory. Powered trolley travel is available as a catalog item and is justified. Powered bridge travel is also justified, particularly in the case of a long, narrow shop. Hoist and powered travel push-button controls should be in a pendant-type box. Capacity should be 2–5 tons (1.8–4.5 tonne).

c. *Precautions*.

(1) When a bridge crane appears justified, early planning is required to assure a powerhouse structural layout permitting adequate shop ceiling and lighting clearance for the bridge.

(2) Structural support for the crane rails is an early planning consideration.

(3) Specifications should require a bridge and hoist capable of withstanding pullout torque forces applied to the hook.

20–20. Floor Cranes

Maintenance shops not equipped with a bridge crane should be provided with a portable floor crane. This includes all shops in 1–4-unit plants and many shops in 5–10-unit plants. The crane should be a standard catalog item, preferably hydraulically operated, manually powered, and equipped with antifriction bearing wheels and casters. A 2–3-ton (1.8–2.7-tonne) capacity should be specified.

20–21. Monorail Cranes

a. The most common powerhouse application for monorail cranes is handling draft tube bulkheads at small powerhouses where the slot location is close to the downstream wall. The rated capacity of the crane should be specified to be the same as that of the hoist, and is the load that the crane is designed to handle while meeting the design criteria defined in paragraph 20–11.

b. Standard catalog units are preferred, and should include proof-testing of the hoist and rail to maximum load (such as motor breakdown torque or MMT as limited by a VFD).

c. Other powerhouse handling applications with lifting and travel requirements in restricted areas may warrant monorail installations. Before a decision is made to use a monorail crane, each requirement should be carefully evaluated for practical alternate provisions, such as embedded lifting eyes and portable hoists or crane hook access hatches permitting lifts to be made with the bridge crane or a deck gantry. Monorail hoists have had some application in maintenance shops but lack the versatility of a bridge or floor crane. See paragraphs 20–9 and 20–11 for discussion on detail design criteria for cranes.

20–22. Jib Cranes

a. Jib cranes have limited application in powerhouses since most areas with adequate head room to accommodate a jib can be serviced with the bridge crane or a deck gantry. They are most suited to hoisting applications requiring limited horizontal movement, as on or off a truck, or a limited transfer movement to or from a location just beyond bridge or gantry crane hook coverage, and locations where an embedded eye and portable hoist are impractical.

b. Mounting a jib crane on a gantry crane leg to handle hatch covers, gratings, or heavy maintenance equipment is sometimes an advantage over using portable equipment or a mobile crane.

c. A good selection of standard catalog jib cranes is available. Manual winches or chain hoists are normally adequate for jib use. Electric hoists are justified if they will be used frequently. The uncertainty of maximum loading with a manual hoist makes it important that jib structural members and anchor bolts be designed with high safety factors. See paragraphs 20–9 and 20–11 for discussion on detail design criteria for cranes.

20–23. Hoists

a. *General*. Fixed hoist applications in powerhouses typically include operation of intake gates requiring emergency closure capability, operation of gates and weirs requiring automatic or remote control, and miscellaneous lifts non-accessible to a crane. Fixed hoists may be of several types, the most common are hydraulic or drum-wire rope. For applications with infrequent and non-critical use (for example, small powerhouses with one or two units where tail race stoplogs are installed infrequently for unit maintenance), portable equipment that is shared between units is preferred to reduce plant maintenance demands.

(1) Intake gate hoists (fixed hoists) are typically used for operation of vertical lift, wheeled, or roller-mounted gates. The primary purpose of these fixed hoists is to

provide emergency closure. They are also often used for unit unwatering to perform maintenance and repair operations of the power tunnel, penstock, turbine intake scroll case, and turbine-generator. Some powerhouses use the intake gate to re-water the unit by slightly opening the gate to slowly fill the turbine intake. See paragraphs 20–2 and 20–3 for design considerations and performance criteria pertaining to emergency closure and gate cracking functions.

(2) Fixed hoists are used at some powerhouses for operating tailrace gates. These are typically used where the risks and level of impact to the powerhouse from tailwater flooding requires automatic or rapid closure of gates. In these cases, layout limitations or timing requirements exclude using a mobile crane to provide the necessary means to shut off water from the tailrace. The most common facilities to use fixed hoists are ones with slant-axis units.

(3) The type of hoist selected depends on the size of gates involved and the configuration of the intake structure and is based on economics and governing criteria for closure times under emergency conditions. The hoisting system for drum-wire ropes may be deck mounted or placed in recesses above the high pool elevation. Cylinders for the hydraulic hoist system are mounted below the deck in the intake gate slot. Because these gates must be capable of operating under full head and flowing water, tractor-type gates are commonly used to reduce friction.

(4) There are three types of fixed hoists that are generally used at USACE powerhouses: direct-acting hydraulic hoists, hoists consisting of hydraulic cylinders connected by wire rope through deflector sheaves to the gates, and drum-wire rope hoists.

b. *Hydraulic Hoists*.

(1) *General*.

(a) Hydraulic hoists normally consist of a single acting cylinder, pumps, reservoir, controls, and piping. The preferred arrangement is to place the cylinder above the gate and support it in the slot. The rod is connected to the gate, and the gate and rod hang from the piston. Two cylinders per gate are common for large gates.

(b) Releasing oil from the cylinders allows the gates to gravity close. The pumps are used to raise the gates.

(c) Where intake and deck elevations do not permit hanging the gate below the cylinder, it may be necessary to recess the cylinders within the gate structure.

(d) Hydraulic hoist systems used for intake gate emergency closure on units with more than one intake gate should be designed so that all gates close simultaneously and at the same speed. Means for adjusting the speed of each gate independently is required to ensure synchronized closure. Hydraulic hoists should be provided with a means of determining gate speed so that closing rate can be verified. Periodic inspection and maintenance procedures should include verification of gate simultaneous closure.

(e) Refer to EM 1110-2-2610 for additional discussion and requirements on hydraulic hoists and the specific components that make up the hoist system. If there are overlapping or conflicting requirements, those contained within this EM govern for hydraulic hoists for powerhouses.

(f) Hydraulic systems and components should be specified according to UFGS 35 05 40.14 10 except where modified by this EM.

(2) *Design*. Design of the hydraulic hoist system is usually the Government's responsibility. Service and size requirements are usually not compatible with commercially available catalog equipment, and suppliers' special designs are contractually difficult to control. The design should be adaptable to a variety of components (such as pumps and control valves, seals, piston rings, cylinder construction), to avoid unnecessary bidding restrictions.

(3) *Operating Configuration*.

(a) Historically, many intake gate systems were designed to use a pressurization pump that maintained the gates in the raised position (sometimes referred to as a floating gate configuration). One of the failure modes of this arrangement has the potential to pump a significant amount of oil into the river if there is a leak.

(b) Design teams for new and rehabilitated intake gate systems should evaluate any historical data on previous spills and any site-specific design details (such as how often the cylinder is submerged) and consider moving to a latched gate configuration that uses a mechanical latch to keep the gates raised versus a pressurization pump. This arrangement maintains operational reliability while significantly reducing the potential maximum volume for an oil spill.

(c) If a latched gate configuration is used, the system should be designed so that the gates can be operated with minimal delays in the event of a total loss of the regular electrical power source. One way to provide this is by using accumulators to store pressurized oil.

(d) If a latched gate configuration is used, the system should be designed so that emergency closure is possible under complete failure of the normal power supply and also under complete loss of pressurized hydraulic fluid. This is a combination of multiple unlikely events; therefore it is acceptable for the means of performing emergency closure in this extremely unlikely scenario to take hours to days to accomplish.

(4) *Hoist Capacity*. Size hoists according to paragraph 20–7.

(5) *System Design Operating Pressure*.

(a) A 3,000-psi (20,670-kPa) design system pressure is recommended. Commercially available hydraulic components for this pressure are very common. Required hoist capacity can usually be obtained with practical cylinder sizes using 3,000-psi (20,670-kPa) pressure as well.

(b) Operating pressures for normal balanced head gate movements or for holding gates in the open position are usually within 1,200–2,000 psi (8,270–13,780 kPa) when cylinders are designed for maximum downpull and breakaway loads at 3,000-psi (20,670-kPa) operating pressure.

(6) *Hydraulic Cylinders*.

(a) Cylinders should be single-acting, mill type. Key dimensions such as stroke length and internal and external nominal diameters should be specified by the designer, but the design of the cylinders should be largely performance specified.

(b) Cylinders should be single stage. Telescopic-type cylinders have been used in the past, mostly as a means of raising the intake gate storage height for fish passage reasons. If possible, they should be avoided for retrofits and new installations as they add additional complexity and potential for leaks.

(c) Many intake gate hoist cylinder installations are such that the cylinders are submerged 100 percent of the time. Cylinders for submerged applications should be

specified with a corrosivity category of CX, per International Organization for Standardization (ISO) 9223.

(d) If possible, the cylinder should be one section. Due to length, most intake gate cylinders have to be made from multiple sections. Cylinder ends should be flanged.

(e) UFGS 35 05 40.14 10 provides multiple options for rod base material and rod coating. Any of the options are acceptable for intake gate cylinders. Cost, operating life, and maintenance considerations should be balanced when selecting the rod and coating materials. Original cylinders to dam installation were largely carbon steel with hard chrome plating, but more modern coating systems such as laser cladding or thermal sprayed should be considered for submerged cylinders. Ceramic rod coatings are not recommended at the time of publishing.

(f) Cylinders can be specified with position indication systems built into the rod. This type of system is not typically needed for powerhouse intake hoists as accurate indication of gate intermediate position is rarely needed. A gate position indication system as described in paragraph 20–23b(19) is recommended instead.

(7) *Latch*.

(a) Systems that use a latched gate configuration should be provided with a hydraulically operated latch to lock the piston and rod in the retracted position.

(b) Systems that use a floating gate configuration can be provided with a hydraulically operated latch, but are often provided with a manually engaged latch to lock the piston and rod in the retracted position for raising the gate to the dogging position with the crane. The engagement is often a threaded connection in the top of the piston rod with the latch pin located in an oil-sealed hole in the cylinder head. If this type of latch is provided, a removable T-wrench should be provided to permit convenient operation of the latch pin.

(c) The latch pin should be made of corrosion-resistant material, typically stainless steel.

(d) If the gate is removed from the slot as an assembly with the support beam and cylinder(s), latching the gate to the beam is also acceptable.

(8) *Pumps*.

(a) *General*. All intake gate hoists in a powerhouse are normally connected to a common pump-piping system. While some plants were originally configured with multiple pumping units, or even a pump unit for each main unit, that arrangement results in significantly higher O&M costs while providing little benefit in reliability. The required operational reliability can be achieved with a single pump unit that uses multiple identical pumps.

(b) *Pump Type*. Pumps should be positive displacement of either the vane or piston type with standard catalog ratings to provide the required displacement and pressure. Pumps should be electric motor driven. Adjustable flow rate, either through mechanical means such as a swashplate or by variable speed control for the pump motors is typically not needed. Across-the-line starting should be provided to reduce system complexity.

(c) *Pump Configuration*. At a minimum, two identical pumps should be provided to provide backup in the event of a pump failure. For systems that use a floating gate configuration, it is usually also desirable to provide makeup oil to maintain pressurization of the system with a separate small displacement pump to avoid frequent

starting or continuous unloading of one of the raising pumps. The small displacement pump may have a higher pressure rating than the raising pumps to aid in breaking loose a gate for equalizing.

(d) *Pump Flow Rate*. Flow rate for the raising pumps should be selected so that a single gate may be raised in approximately 20 minutes or less. If a separate pump is provided to maintain system pressurization, it should be sized to deliver 150–200 percent of the anticipated leakage.

(e) *Mounting*. Pumps should be mounted to provide a positive suction head and be equipped with auxiliaries recommended by the manufacturer. Relief or unloading valves should be provided to limit maximum stress in hoist components to 75 percent of yield point. The 75 percent yield point pressure should be the maximum relieving pressure to which the valves can be adjusted.

(9) *Directional Control Valves*. Directional control valves should be provided for controlling raising and lowering operations and latch/latching pin operations (if equipped). Valves should be suitable for remote control operation. Remote operation should not be provided for raising the gates to minimize possibility of accidental raising of a gate on an unwatered unit.

(a) *Valve Type*. Valves may be rotary shear-, poppet-, or spool-type valves, but should be essentially drop tight at gate support pressure. For systems that operate infrequently, spool valves may not be the preferred type due to potential leaking and sticking issues.

(b) *Valve Sizing*. Use standard valve sizes. Where the same valve is used for lowering and raising (such as a rotary shear type), valves should be sized based on lowering flow rates as they are much higher than raising flow rates. Where separate valves are used to control each motion, size valves for the expected flow rate for their intended purpose.

(c) *Operation*. Rotary shear-type valves may use hydraulic cylinder rotary actuators. Poppet- and spool-type valves should be pilot operated. Solenoid valves in the pilot circuit are normally used to control valve remote operation. Manual operators should be provided for all valves to allow use of the valves in the event of loss of control power.

(d) *Options*. Two valves in parallel or a manual override option should be provided to allow emergency closure in event of a single valve malfunction.

(10) *Flow Control Valves*.

(a) *Lowering*. A pressure-compensated, adjustable-flow control valve should be provided in the high-pressure line from each cylinder to regulate gate lowering speed and to match lowering speeds where more than one gate per unit is required.

(b) *Raising*. Additional flow control beyond the pump flow rate is not needed for raising, as it is not important if the gates are synchronized.

(11) *Isolation Valves*. Isolation valves should be the quick-acting, low-operating force type suitable for panel mounting. Ball valves are a common type used. A valve should be provided in the high-pressure line to each cylinder to permit individual manual gate control and to isolate the cylinder from the hydraulic system.

(12) *Pump Controls*.

(a) A pump control panel should be provided adjacent to the pumping unit.

(b) If one is provided, the pressurization pump should be on automatic start-stop pressure control to maintain system pressure above minimum no-drift pressure. A manual momentary-contact override switch should be provided at each panel to permit applying temporary breakaway pressure. Pump relief-unloading valve settings should normally be about 5 percent above normal maximum system operating pressure.

(c) Raising pumps should be on manual start with adjustable time-switch shutdown. Remote start of the pumping unit should be provided at each unit hydraulic control panel.

(13) *Gate Controls*.

(a) Gate movement controls and valves for one main unit should be mounted on one common control panel at each unit, generally in a gallery near the gate slots. A steel panel designed for standard panel mounted hydraulic valves is preferred.

(b) For intake gates, a semi-automatic emergency closure function should be provided that is actuated via a single switch. The switch should activate a sequence that simultaneously and automatically closes all gates. At a minimum, switches for the emergency closure function should be provided at the gate control panel and in the control room. Additional switches are often provided at each governor actuator cabinet.

(c) Using a programmable logic controller for gate control is generally preferred, though hardwired controls can also be used if requested by the operating project.

(14) *Pipe and Tube*.

(a) *High-Pressure Piping*. For service above 300 psi (2068 kPa), use Schedule 80 seamless with socket welding fittings.

(b) *Low-Pressure Piping*. For service below 300 psi (2068 kPa), use Schedule 40 with socket welded fittings.

(c) *Tube*. Using tube is acceptable for sizes less than 1 in. nominal.

(d) *Materials*. For piping that is outside and/or submerged, due to both internal and external corrosion problems, the piping should be stainless steel such as ASTM A312, Grade TP304. Carbon steel piping is acceptable for all pipe contained within the powerhouse and where water contamination inside the pipe is not a high concern.

(e) *Header Sizing*. If it is necessary to use two oil reservoirs on a single system, the equalizing header between them should be substantially oversized to preclude overflow from unbalanced return flows.

(f) *Low Pressure Pipe Sizing.* Low-pressure piping should be sized to provide a positive head throughout the system unless there are minor, short-duration, negative pressures under emergency closure operation.

(15) *Reservoir*.

(a) Depending on the size of the plant, one or more reservoirs may be needed. The reservoir(s) should be sized to contain the displacement of all piston rods on the system plus the volume of one cylinder, 15 percent reserve oil, and 15 percent air volume.

(b) Generally, reservoirs should be made from carbon steel that is painted. Making reservoirs from stainless steel or aluminum is generally not needed.

(c) Reservoirs should have an interior painted finish with a white topcoat. While hydraulic fluids typically do not cause tank corrosion on their own, the head space of most reservoirs are open to the atmosphere that allows ambient moisture to enter the tank. Additionally, water that has leaked into the system and is mixed with the fluid can

cause corrosion. System 21-A-Z in UFGS 09 97 02 Painting: Hydraulic Structures, an epoxy-type paint, is recommended, but compatibility with the chosen hydraulic fluid should be checked prior to finalizing coating selection. The epoxy system in UFGS 09 97 13.17 can also be used, though substituting in the zinc-rich primer from System 21-A-Z for improved corrosion resistance is recommended.

(d) Exterior of the reservoirs can be coated with any paint system in UFGS 9 97 02 that is recommended for atmospheric exposure.

(e) Reservoirs should be located to assure a positive system head and should be heated as required to preclude condensation.

(16) *Accumulators*. Accumulator capacity on the system should be sufficient to ensure a pressurizing pump cycling time of not less than 10 minutes.

(17) *Hydraulic Fluid*.

(a) Hydraulic fluid selection should be consistent with EM 1110-2-1424. Cold weather and low temperatures should be taken into account when selecting the viscosity of the fluid.

(b) EALs are lubricants and fluids that meet certain criteria for biodegradation, bioaccumulation, and aquatic toxicity. EM 1110-2-1424 has extensive discussion on EALs and applications with USACE facilities.

(c) When considering a replacement or major rehabilitation of a hydraulic hoist system, or replacing major components such as the cylinders, conversion to a system specified to use an EAL hydraulic fluid is proactive and recommended.

(d) Converting to EALs while using current in-service equipment is not recommended without approval of the manufacturers of all components in the system, or extensive work to confirm compatibility with the existing fluid and components.

(18) *Support Beam*. The support beam is the structure that supports and suspends the hydraulic cylinder and gate in the gate slot.

(a) *Design*. The support beam is a BTH device. Refer to paragraph 20–24. The support beam may be loaded in different combinations and all need to be considered during design. These can include support during normal gate operation, emergency closure, and lifting the cylinder/gate assembly out of the slot.

(b) *Fabrication*. The support beam should be made out of structural steel. Welding should be to AWS D1.1 and weld inspection should be to the AWS D1.1 cyclic criteria. Beam design should be such that all welds are accessible for inspection after fabrication is complete. Bearing surfaces should be machined to assure uniform contact. Support beams that are continually subject to immersion should be painted with one of the USACE vinyl paint systems, preferably System 5-E-Z, per UFGS 09 97 02.

(c) *Connection to Cylinder*. Support beams should provide a connection method to the cylinders that can be field disassembled. If cylinders and support beams are being replaced at the same time, consider allowing the Contractor to design this interface according to performance requirements.

(d) *Immersion*. Support beams that are continually subject to immersion should have a cathodic protection system that uses an array of sacrificial anodes. Anodes should be replaceable and located in areas that are accessible without disassembling the beam.

(19) *Gate Position Indicator*.

(a) When gate position indicators are not otherwise provided, they should normally be included with the hydraulic hoist design. They are essential with hydraulic hoists to monitor gate position and to obtain prompt indication of gate drift. Stainless tapes connected to the gate tops with tension maintained by counterweighing or spring take-up reels have given satisfactory service.

(b) Original installations usually did not include indication of gate position in the control room. Rehabilitations and new projects should consider adding additional indication to the control room so that operators have open and close status for each gate.

c. *Wire Rope Hoists*.

(1) *General*.

(a) Wire rope hoists normally consist of a cable drum or drums and a system of sheaves and blocks that are electric motor driven through an arrangement of shafts, speed reducers, and spur or helical gears.

(b) Wire rope hoists are applicable to intake configurations requiring gates with deep submergence or gates with shallow settings, either of which make hydraulic hoists undesirable. Unusually deep gates require several rod extensions resulting in slow installation and removal of cylinder-operated gates. Shallow gates may require portions of a hydraulic hoist to be above deck level, interfering with vehicle movement over the deck.

(c) Individual stationary hoists are usually provided for operating each service gate. The gates are normally held by the motor brake in the operating position just above the waterway, and control switches are provided at the unit governor cabinets and in the control room to permit rapid closure in an emergency. Local hoist controls, along with reliable gate position indicators, should also be in a gallery close to the hoist.

(d) Arrangement of the hoists varies greatly depending on the intake configuration. Hoists may be located below or on the intake deck, adjacent to or over the gate slots. When located on the deck over the gate slots, provisions should be made for uncoupling the hoist blocks when the gates are in the upper dogged position, and for removal of the hoists from over the gate slots to permit transfer of the gates to the gate repair pit by using the intake gantry crane.

(2) *Design*. Design of wire rope hoists are usually a responsibility of the Government to size the hoist and determine the service and size requirements based on design criteria defined in paragraphs 20–9 and 20–11. The design team should design the hoist and size/select common commercially available components (such as motors, brakes, gearboxes) when feasible to avoid unnecessary bidding restrictions.

(a) Wire rope hoists may require one or more intermediate BTH devices connecting the block to the gate. These BTH devices may be loaded in different combinations and all need to be considered during design. These can include normal gate operation, emergency closure, and gate cracking.

(b) The motor is usually 460-V, 3-phase, 60-cycle, squirrel-cage, induction type with suitable enclosure. Multiple speeds, using relay-based controls, are sometimes provided to permit a lowering rate (up to two times) greater than the raising rate.

(c) The hoist brake should be of the shoe type, spring set, DC magnet or AC thruster, with a watertight enclosure and a capacity of not less than 150 percent of the full load torque of the motor.

(d) The wire rope should be made of stainless steel with an independent wire rope core. During normal operation, the lower block is immersed, with part of the associated reeving immersed and part exposed. Refer to EM 1110-2-3200 for information and criteria important to the selection, installation, inspection, and maintenance of wire rope and fittings.

(e) When the hoist is located on the intake deck over the slots, the hoist machinery should be mounted on a platform of sufficient height so that the gate can be hoisted to a dogging position where it can be readily uncoupled at intake deck level. With this arrangement, the hoist machinery frame and support columns form an integral structure designed to support the hoisting machinery and gate, including provisions to permit its removal from over the gate slot by using the intake gantry crane. Base plates with locating pins should be provided in the intake deck structure to permit quick and accurate equipment reset. Machined bearing pads to support machinery components, necessary openings to provide clearance for ropes and moving parts, and grating to permit inspection and maintenance should be provided.

(f) When hoist machinery platforms are replaced, they should include provisions for 100 percent oil volume containment from operating machinery such as speed reducers.

(g) A minimum area of open grating should be provided for airflow when the supply is through the service gate slots in which the required area should be based on a maximum air velocity of 150 fps (45 m/s).

(h) Sockets embedded in the intake deck concrete permit installation of safety hand railing around the gate slots when grating and/or hoists have been removed.

(i) The motor controller for each hoist should be housed in a watertight control cabinet supported from the hoist frame. A traveling nut-type or intermittent geared-type high-accuracy limit switch and a dial-type gate position indicator, as well as a slack cable limit switch, balanced pressure switch, and an extreme upper travel limit switch, are provided. Accuracy of limit switch trip and reset should be considered when gate cracking or other similar accurate positioning is needed, especially for gates with long travel. Removable power and control plugs should be furnished to permit disconnecting of all incoming leads to the hoist prior to its removal.

(j) Load cell feedback for hoists is recommended. See paragraph 20–14d(4).

(3) *Location*. Wire rope hoists should be located on the deck when practicable. Locations in recesses below the deck may be required where deck access is impaired by a deck location. Hoist controls and gate position indicators should be located per paragraph 20–23c(1)(c).

(4) *Power Failure Operation*. When it is necessary to make provisions to lower the gates without power, brake release and means of speed control should be provided, such as a hydraulic pump driven by the hoist motor with an oil reservoir and flow control valve. If a hydraulic pump is used, a dual-purpose hydraulic pump motor replacing the electric hoist motor should be considered.

20–24. Below-the-Hook Lifting Devices

a. General.

(1) Crane and hoist lifts may require one or more intermediate devices connecting the crane/hoist hooks or blocks to the load, and certain lifts require a device for supporting the load in storage or intermediate positions. These intermediate devices are referred to as BTH lifting devices, and include but are not limited to lifting beams, adapters, spreader beams, support beams, and “dogs.”

(a) Support beams are the structure that supports and suspends the hydraulic cylinder and gate in the gate slot. Support beams are typically procured with the hydraulic cylinder equipment.

(b) Dogging devices (“dogs”) are used with gates and/or bulkheads to temporarily support the gate/bulkhead in a full or partially raised position. The dogging devices relieve the load on the operating machinery during gate/bulkhead temporary storage, and to facilitate maintenance or repair of the machinery or gate/bulkhead while in the raised position. Dogging devices are typically procured with the gate/bulkhead.

(2) Standard rigging-type slings should normally be selected and procured by construction or operations offices.

(3) Lifting beams, spreader beams, or lifting attachment devices (such as a generator rotor lifting device) are usually procured either with the crane or equipment that is chosen.

(4) Powerhouse bridge-gantry equipment differs appreciably from intake gantry and draft tube crane equipment, and coverage herein is divided accordingly. Intake hoist lifting devices are covered by paragraphs 20–24a and 20–24b and applicable provisions of paragraph 20–24d.

(5) A lifting eye that is permanently attached/integral to a piece of equipment is part of the load, not part of the BTH lifting device or rigging.

b. Design. If possible, lifting devices should be designed during the design phase of the project to ensure proper fit and interface to the equipment being handled. If designed during construction or operation phases, the engineer must review and approve the design. Design USACE BTH lifting devices according to ASME B30.20, ASME BTH-1, EM 385-1-1, and paragraphs 20–9 and 20–11.

c. Powerhouse Bridge/Gantry Crane Lifting Devices.

(1) *General*. Lifts made by the powerhouse bridge or gantry cranes are accessible for visual observation and also to personnel for attachment and release. This permits design based on known loads and manual means of connection and release.

(2) *Lifting Beams*.

(a) Cranes with more than one main hook require lifting beams to connect the hooks to generator rotor and turbine runner assemblies. A single beam is required with a single, two-hook crane and three beams with two, two-hook cranes. The beams should provide convenient manual connections of the load to the crane hooks, essentially moment-free, vertical lifting forces on the load, and stable operation under all loaded or unloaded conditions. The generator rotor lifting beams are normally designed and furnished under the crane contract. The lifting devices (such as a rotor bell, lifting yoke, turbine lifting device) that bolt to the turbine or generator are normally designed and furnished by the turbine or generator manufacturer, respectively.

(b) Detail design requirements are covered in paragraphs 20–9 and 20–11. Cooperation between the crane contractor and generator-turbine contractors to assure fit and utility of the lifting beams is required under the supply contracts. The design office is usually required to do preliminary design and beam layout to assure a practical powerhouse structural layout and crane clearance diagram.

(3) *Adapters and Attaching Devices*. Adapters for fitting the lifting beam to the generator rotor and turbine runner assembly are a responsibility of the generator-turbine contractor under the relevant contracts.

(4) *Slings*. Slings for major lifts (such as a turbine and generator) of the powerhouse bridge-gantry cranes are not required. Lifts requiring slings and rigging should be done with commercial off-the-shelf slings wherever feasible, and should be manufactured, used, inspected, and maintained consistent with requirements and provisions of ASME B30.9 and EM 385-1-1 and rigging hardware according to ASME B30.26.

(5) *Compliance*. See Chapters 5 and 6 for additional considerations for verification of EM 385-1-1 and ASME BTH compliance of existing lifting devices prior to unit major rehabs.

d. Intake Gantry and Draft Tube Gantry Crane Lifting Devices.

(1) *General*. Intake gantry and draft tube gantry cranes are regularly used for handling gates, bulkheads, stoplogs, and fish guidance equipment below the water surface where the point of attachment to the load is non-visible and non-accessible to operating personnel. Obstructing debris or silt can hinder operations, and “cocking” or “binding” of the load or lifting beam in the slots can occur. Slings remaining attached to the submerged load or lifting beams with dependable remote control of latching and unlatching are required. Most lifts can be made with either an attached sling or a lifting beam, and the selection should be made only after careful consideration of the following factors:

(a) Dependability. In all cases, dependability favors an attached sling since the potential for latching and unlatching problems, as well as the uncertainty of a secure latch having been achieved, is eliminated.

(b) Sling Size. Sling size may become large enough to cause handling and storage problems.

(c) Hook Travel Limitation. Limited crane hook travel combined with deep load settings may require several dogging operations with slings and a consequent impractical time requirement.

(d) Multiple Unit Loads. Where more than one gate, bulkhead, or stoplog section are required in a single slot, slings are usually impractical. Design of lifting equipment for underwater loads should normally be based on pullout or maximum controlled torque lifting forces. Exceptions should be clearly noted and justified in the mechanical design memorandum. The expense and hazards of diver operations to remedy faulty operation plus monetary loss from delay in returning generator units to service warrant maximum design emphasis on reliability.

(2) *Lifting Beams*.

(a) Lifting beams may be provided for intake gates and bulkheads, draft tube bulkheads, trash racks, fish guidance equipment, and for miscellaneous small gates and bulkheads in water conduits, fish channels, and sluices.

(b) Weight-operated latching mechanisms are operated either with manual tagline actuation or mechanical/automated actuation to perform the latching/unlatching function.

(c) When manual tagline operation is provided, it should be assumed a one-man effort, and maximum required rope pull should not exceed 50 lbf (223 N). The design should have clearances and dimensions that provide source engagement of alignment pins with sockets, hooks with latches, and latching pins with sockets, with all accumulated construction and installation tolerances considered. The moving latches/hooks/pins should be mechanically linked together to assure simultaneous movements and consider greaseless bushings for linkage pivot joints of the latching linkage mechanism.

(d) Mechanical/automated operation using latching hoists may be necessary when: (1) the physical size of latches, hooks, or pins make manual operation infeasible; (2) the operating project does not have the rigging crew size to manage a manual tagline; and/or (3) fall hazards associated with manual tagline operation make the operation unsafe for riggers. If latching hoists are used, they should be designed consistent with paragraphs 20–9 and 20–11 and include controls for latching, unlatching, and slack rope (for replacement of hoist wire rope).

(e) Latching pin/hook position indication should be considered when feasible because lifting beams for intake gantry and draft tube gantry operations are submerged with the gate/bulkhead resting on the sill and the latching operation is not visible to the operator/rigger. There are various methods that have been used for latch/pin/hook position indication, for example: (1) proximity switch; (2) encoder counts on latching hoist motor/drum; and (3) physical monitoring of latch line movement. However, the methods used are operator and rigger assistance tools and should not replace an operator’s experience with monitoring LHE during raising/lowering and observing load monitoring displays during initial movements after a latch/unlatch operation.

(f) Beam length to guide height proportions should minimize wedging tendencies in guides, or end clearances should preclude wedging. Weight of lifting beams is normally a minor factor in total lifting loads. Therefore, heavy and rugged designs are desirable to stand up under severe operating conditions and to ensure positive lowering and latching through debris.

(g) Multipurpose beams requiring a variety of special adapters, special guide shoes, length or offset adjustments, and interchange of hooks are not recommended.

(h) An assembly drawing for each beam should be included in the mechanical design memorandum showing slots, load pins, beam hooks, aligning pins when applicable, guide shoes or rollers, operating mechanism and critical dimensions, tolerances, and clearances indicating correct operation under all conditions.

(i) A single lifting beam is normally provided for intake bulkheads, gates, and fish guidance equipment. Early coordination of gate, bulkhead, fish guidance equipment, and slot design to assure a practical single lifting beam without adapters is necessary. Procurement is usually included in the intake gantry crane supply contract, and final design is the Contractor’s responsibility. See paragraphs 20–9 and 20–11 for design criteria.

(j) Basic structural and mechanical unit stresses should be consistent with the applicable requirements discussed in paragraphs 20–9 and 20–11 with normal loadings

considered as lifting loads plus friction and pullout loadings based on the applicable crane hoist. Pullout loadings for mobile cranes should be considered for tipping loads. Hooks should be mechanically linked together to assure simultaneous movements.

(3) *Slings*.

(a) Commercial off-the-shelf slings should be used wherever feasible, and should manufactured, used, inspected, and maintained according to requirements and provisions of ASME B30.9 and EM 385-1-1.

(b) Special-purpose slings for intake gantry and draft tube gantry crane use should be made of corrosion-resistant steel wire rope and galvanized fittings, or alloy steel chain. Synthetic slings have become more common and are acceptable as long as they are used consistent with manufacturer’s requirements, including using softeners at corners, and inspected per ASME B30.9. The design and sizing requirements must be consistent with paragraphs 20–9 and 20–11, ASME B30.9, and EM 385-1-1 for additional design and safety factor requirements for slings (the most conservative criteria must govern).

(c) Sling clevis pins and other pins requiring disassembly under normal use should have ample clearance to minimize binding under average field-handling conditions. A 1/16–1/8-in (1.6–3.2-mm) clearance is preferred for average field-handling convenience. Design of intermediate links, storage links, support beams, and sling storage provisions should consider convenience and safe handling along with required strength.

20–25. Miscellaneous Wire Rope Hoists

a. *General*. Fixed wire rope hoists may be required for lifting applications inaccessible to cranes or for control gate operation where frequent adjustments or automatic controls are necessary. Some powerhouses use fixed wire rope hoists for draft tube access (personnel hoists), where personnel are lowered through the draft tube access door to perform inspection and maintenance. Portable commercial equipment is preferred whenever practicable. Powerhouses with fish passage facilities frequently require fixed hoists for weir adjustment and control gate operation. Fixed hoists may occasionally be justified for ice and trash sluice control gates. Fish facility equipment criteria are normally supplied by fishery agencies; however, powerhouse design responsibility includes safety, dependability, and satisfactory service life.

b. *Design*. Per paragraph 20–23c, underwater bearings should be water lubricated except where presence of abrasive silt requires sealing. The cost of miscellaneous wire rope hoists is often moderate and may not appear to justify extensive engineering. However, several factors can affect satisfactory operation, maintenance, and service life. The design procedure should not shortcut the necessary investigations, which include the following:

(1) *Climatic Conditions*. These conditions include the effects of ice, moisture, and heat.

(2) *Water Quality*. The presence of abrasive silt or unusually corrosive materials in the water should be considered.

(3) *Gate Guide Alignment, Material, and Clearances*. These factors, while not primarily a mechanical design responsibility, can materially affect hoist operation, so coordination with the responsible design group is necessary. The possibility of gates temporarily “hanging-up” is often overlooked.

(4) *Water Hydraulic Conditions*. The possibility of unusual turbulence, surging, or wave action causing added hoist loading, uplift, or vibration should be investigated.

(5) *Examples*. See Figure 20–13 through Figure 20–15 for examples of structural design criteria load combinations.

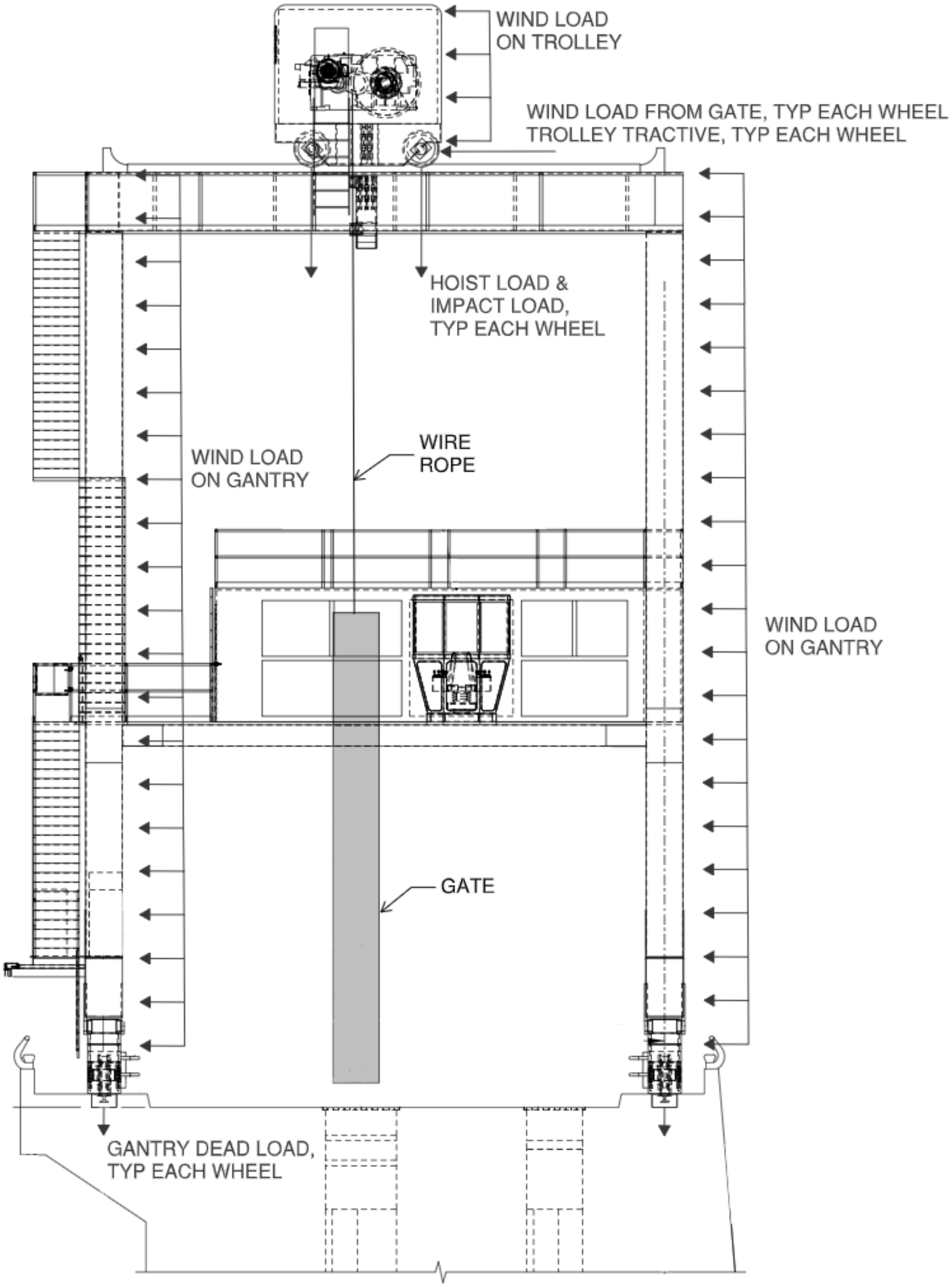


Figure 20–13. Category I load combination example

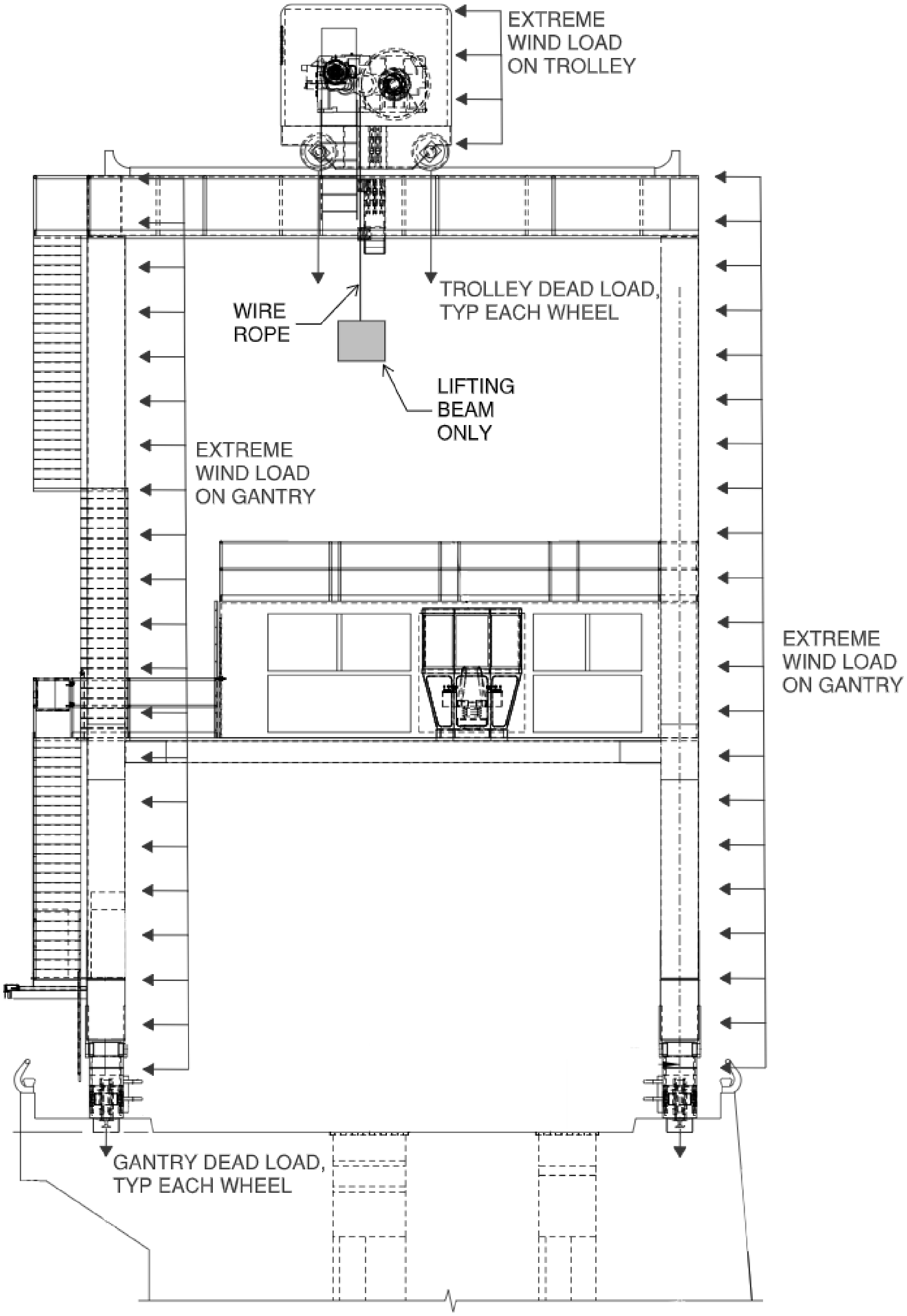


Figure 20–14. Category II load combination example

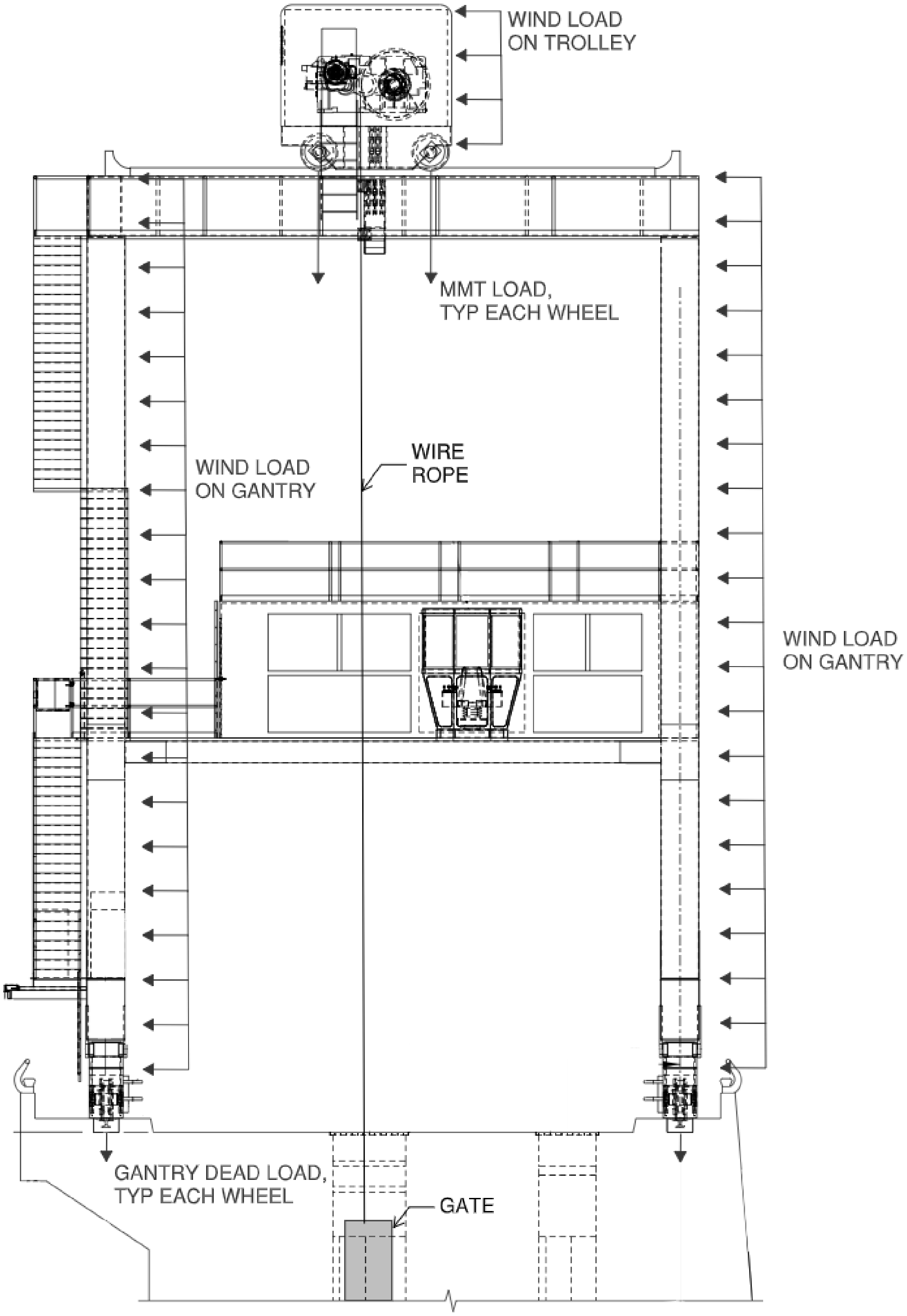


Figure 20–15. Category III load combination example

Chapter 21
Fire Protection Systems

21–1. General

Fire protection systems have been in service in USACE hydroelectric facilities constructed as early as 1938 and as late as 1989. National fire codes have been in existence since original construction of most hydroelectric facilities. Most facilities complied with current fire code requirements at the time of construction. Fire protection systems require regular maintenance and testing to ensure availability and proper function.

a. Projects involving facility alteration or modification as well as the upgrade, modernization, or replacement of equipment require a fire protection analysis that includes life safety analysis. The concept that existing equipment is “grandfathered” to operate indefinitely as originally configured or is exempt from modern code requirements analysis is invalid. All aspects of fire protection as well as environmental, structural, and electrical aspects must be investigated and identified for all equipment that poses a fire hazard. Requirements for all designs are contained in paragraphs 21–2 and 21–4.

b. Powerhouses are generally low fire hazard structures due to construction consisting primarily of reinforced concrete and masonry. Most existing powerhouses contain automatic fire protection systems for the following specific hazards:

(1) Oil storage and oil purification rooms,
(2) Paint and flammable and combustible liquids storage room,
(3) Hydroelectric generators, and
(4) Oil-filled transformers and breakers.

c. Principal fire protection for most other areas and hazards in existing powerhouses is by portable extinguishers. Facilities sometimes contain hose stations intended to provide both washdown and fire-fighting capability. Only those hose stations and hydrants served by a dedicated fire pump and pipe system meet national fire code requirements. All shared or combination washdown and hose station water systems are unacceptable for continued use for firefighting. Facility operating personnel are not trained for fire-fighting brigade and as such, not required or expected to operate hose stations. Only professional firefighting personnel should use hose stations. Fire protection water mains and hydrants are rarely present on existing powerhouse sites and access is not publicly available.

d. Individual fire alarm control panels (FACPs) were typically installed for each of the fire protection systems for the oil storage and oil purification rooms, paint and flammable and combustible liquids storage room, hydroelectric generators, and transformers. FACPs were in close proximity to the room(s) protected. FACPs provided both local alarm and notification in the immediate areas and remote annunciation, most often on the control room switchboard. FACPs were relay-based custom builds and not interconnected one to another (not networked).

e. Plant-wide fire detection and alarm systems are not typically found in originally constructed powerhouses. Some plants contain a retrofit fire alarm and detection system as serving the regularly occupied office and shop areas. As of 2020, several plants have begun to receive modern fire detection and alarm systems throughout the entire powerhouse and in some cases, adjacent operating facilities.

f. Powerplant fire protection systems and fire alarm and detection systems do not automatically contact local fire department(s). The existing established means of fire notification and its management in the powerhouse is by the plant operator. The plant operator notifies both operating personnel and, as needed, professional firefighting personnel via 911 emergency service. Notification is based on fire protection system annunciation in the control room, other operating personnel, or a plant-wide fire detection and alarm system. Most powerplants are remote, with varying response times anywhere from 11 to 30 minutes, or more.

21–2. Design Criteria

a. All fire protection design must be consistent with the most current edition of UFC 3-600-01. This UFC contains the specific fire protection systems for all hazards of the powerhouse.

b. As part of the DoD's consolidation in design criteria in 2002, the UFC program was established for the construction of new facilities and the continued operations, maintenance, and upgrading of existing facilities. This UFC is regularly updated through major revisions and incremental changes. This UFC establishes the minimum fire protection requirements for DoD facilities and is based on national fire codes. The requirements in this UFC reflect the need for protection of life, mission, and property (building or contents) while considering the costs of implementing the criterion and risks associated with the facility.

(1) Regarding conflicts between this UFC and any other DoD document, national fire code, referenced code, standard, or publication, this UFC takes precedence.

(2) This UFC contains requirements for general items pertinent to all facilities, occupancies, and systems (such as life safety, qualified fire protection engineers, design analysis, building construction, water supplies, fire extinguishing systems, and fire alarm systems).

(3) This UFC also contains requirements for "Special Detailed Requirements Based on Use" that provide specific criteria for special or unique occupancies and hazards in addition to the general items.

(a) UFC section "Hydroelectric Generating Plants" contains primary requirements for new and existing hydroelectric facilities and fire protection systems. The systems included are oil storage and oil purification rooms, paint and flammable and combustible liquids storage rooms, hydroelectric generators, and transformers. This section required mandatory adherence to NFPA 850 in the 2018 edition of the UFC. The most current published UFC contains the latest requirements pertaining to national fire codes.

(b) UFC section "Power Generating and Utilization Equipment" contains secondary requirements for equipment not contained in section "Hydroelectric Generating Plants."

(c) This UFC identifies design personnel qualifications as well as the authority having jurisdiction (AHJ) for both design and post-award phases.

(4) Requirements of this UFC apply to all building reconstruction, additions, alterations, and equipment replacements, relocations, and/or upgrades. Requirements apply to life safety and fire protection design.

(5) USACE designers must use the most recent UFC publication at design start.

(6) Architect-engineers performing design services must use the most recent UFC publication at design start or the publication date contained in the scope of work.

21–3. Operation and Maintenance Inspection, Testing, and Maintenance of Fire Protection Systems

a. All fire protection system operation, maintenance, inspection, and testing must be consistent with the most current edition of UFC 3-601-02.

b. Electricians and mechanics are often able to perform general system maintenance. Some actions require advanced and specialized certifications and/or training. This UFC establishes personnel training and certification requirements. USACE personnel performing advanced operations must meet the requirements of this UFC.

21–4. Design Submittals

Design submittals for fire protection systems are of a performance nature for USACE, regardless of contract type. Provide fire protection design analysis in compliance with UFC 3-600-01. The use of performance specifications is also typical for most non-Government fire protection design submittals in commercial industry.

a. At a minimum, designs consisting of plans and specifications should indicate:

(1) Mandatory demolition.

(2) Utility connections for power, water, drainage, and any other utility required for the operation of the equipment.

(3) System type(s) with estimated system demands.

(4) Protected zones or areas of coverage.

(5) FACP location(s) and minimum features.

(6) Envelope space(s) for new equipment.

(7) Concentration or density requirements.

(8) Location of pull stations and detection, and notification appliances.

(9) Estimated sprinkler and nozzle locations.

(10) Materials of construction for all components.

(11) Primary and secondary containment.

(12) Special site conditions, modification or alteration of existing systems, and any special constraints in construction phasing or testing.

b. Fire protection design submittals may be prepared only under the authority of individuals having qualifications and experience as Fire Protection Engineers as specified in UFC 3-600-01.

21–5. Shop Drawings

Detailed, final design shop drawings are contractor prepared only by individuals meeting the fire protection qualifications as Fire Protection Engineers or NICETY-qualified levels as listed in UFC 3-600-01. (NICET stands for National Institute for Certification In Engineering Technologies.)

21–6. Oil Storage and Oil Purification Rooms

Install a fire suppression system in oil storage and oil purification rooms as required by UFC 3-600-01.

a. Oil storage rooms contain large quantities of transformer and lubricating oil in steel tanks. Oil purification rooms contain smaller tanks and filtration machinery and supplies. Along with fire resistive construction, a fire suppression system limits damage within the rooms and limits the spread of smoke and noxious fumes through the powerhouse. Rooms must not be used for the storage of volatile, low flash-point materials susceptible to explosion and combustible materials such as paper products.

b. Originally constructed oil storage and oil purification rooms were typically protected by a high-pressure CO_2 fire suppression system. The rooms typically contain a depressed slab for oil containment. For compartmentation, the rooms used CO_2-actuated closure devices on sliding doors and HVAC grilles, registers, and ducts either serving or passing through the rooms. Due to these rooms being occupiable and CO_2 presenting a significant health risk to personnel, this type of system is recommended for replacement.

c. Originally installed CO_2 fire suppression systems are of the total-flooding type that effectively reduces the oxygen level of the space through the addition of a gas which displaces the air, limiting further combustion. Systems typically contain a battery of high-pressure storage cylinders, or tanks, containing liquid CO_2.

(1) A heat detector or manual pull station initiates an alarm at the FACP, sometimes called the "releasing panel." A 20-second time delay starts and once complete, automatically releases the liquid CO_2 source. The time delay allows personnel to safely exit the space at a fire-code determined nominal speed. Liquid CO_2 is close to 900 psi (6205 kPa) at ambient powerhouse temperatures. CO_2 flows through a piping network and out of the nozzles located on the ceiling throughout the room(s). Manual operation of a mechanical cylinder release at the CO_2 source also results in system discharge.

(2) On discharge, the CO_2 changes phase from liquid to gas and absorbs heat, providing a cooling effect in the space as well as air displacement. The pressurized CO_2 is also typically used to operate releasing devices. Releasing devices are found on weighted, automatic closing rolling fire door(s) and on HVAC closure dampers for ducts located at wall penetrations for supply, transfer, or exhaust air ducts. Resulting CO_2 concentration in the space is above 30 percent and hazardous to human occupants.

(3) For increased operating personnel safety, consider replacing the existing CO_2-based fire suppression system with a suppression system according to UFC 3-600-01.

(4) Ensure that existing CO_2 systems are fully functional and tested according to UFC 3-601-02.

(a) Consideration should be given to the addition of an automated CO_2 bottle weight management system for enhanced personnel safety through active leak detection. The current requirement for CO_2 bottle weight inspection is every six months per UFC 3-601-2 and NFPA 12.

(b) Consider the addition of an odorizer for enhanced personnel safety. The odorizer is a small cylinder containing a wintergreen oil that mixes with released CO_2 to provide a strong wintergreen odor indicating CO_2 presence.

d. CO_2 is prohibited for use in replacement systems as stated in UFC 3-600-01 section "Hydroelectric Generating Plants." Additionally, NFPA 12 prohibits CO_2 systems in rooms occupiable by personnel.

e. Approved replacement fire suppression systems are only those listed in the most recent publication of UFC 3-600-01 section "Hydroelectric Generating Plants."

(1) Although water mist and clean agent suppression systems replaced CO_2 suppression systems in 2018, only the UFC contains the latest acceptable system types.

(2) Replacement system designs must conform to UFC requirements for the year in which designed.

(3) Originally installed FACPs may not be reused; they must be replaced with new fire alarm control units (FACUs).

(4) Originally installed fire detection and notification devices may be considered for re-use where network address module retrofitting is supported and permitted by UFC requirements.

(5) Originally installed sliding doors must be replaced with fire-rated doors meeting NFPA 101 life safety requirements for storage occupancies.

(6) Original CO_2-actuated HVAC dampers must be replaced as complete assemblies containing electrical actuators specifically listed for fire protection. The field modification of existing assemblies through the replacement of the actuation device is not permitted.

(7) Oil pumps must contain an electrical interlock to de-energize the motor during alarm.

(8) A system discharge validation must be performed for at least one of each system installed. The test must validate media discharged and applicable concentration levels required. For example:

(a) Water mist systems must have one room or zone discharged. Preferred validation is for direct water mist observation. Other discharge methods may be as acceptable by the applicable NFPA code and AHJ.

(b) Clean agent systems must have at least one room or zone discharged. The oxygen concentration must be sampled to determine agent concentration within the prescribed duration.

(c) Once initiated, suppression agent flow continues until fully discharged. Planning is required to contain suppression agent to protect personnel, property, and the environment.

21–7. Paint and Flammable and Combustible Liquids Storage Room

Install a fire suppression system in paint and flammable and combustible liquids storage rooms as required by UFC 3-600-01.

a. A paint and flammable and combustible liquids storage room contains paint, lacquers, thinners, cleaners, and other volatile, low flash-point material. The fire suppression system features and benefits are the same as that found in oil storage and oil filtration rooms. A paint and combustible liquids storage room must not be used for the storage of combustible materials such as paper products.

b. Originally installed fire suppression systems are the same as those found in oil storage and oil filtration rooms.

c. All recommendations regarding the maintenance, replacement, and all other aspects of the paint and flammable and combustible liquids storage room must be as specified for oil storage and oil filtration rooms.

d. A paint and flammable and combustible liquids storage room is recommended to be no less than 100 sq ft (9.3 sq m).

21–8. Hydroelectric Generators

Install a fire suppression system in hydroelectric generators as required by UFC 3-600-01.

a. The stator of the generator is where most of the electrical energy of the hydroelectric generator is concentrated or contained. The enclosure covering the generator (air housing) contains other ancillary devices such as CTs, grounding resistors, thermoplastic end-turn windings, insulated cable, and other foreign and airborne materials such as dust and bearing oil. The air housing is a normally unoccupied enclosure, or space.

b. The primary fire hazards of the generator are contained in the air housing and include the possibility of an electrical fault in the stator windings or the combustion of ancillary equipment, dust, or oil. CO_2 fire protection systems were therefore provided in the air housing of most of USACE’s originally installed main unit generators along with many station service generators.

c. NFPA 12 specifically addresses the design of CO_2 systems for protection of rotating electrical equipment. The standard further categorizes the windings as a fire category of “deep seated” fires involving solids subject to smoldering. Work on this standard was initiated in 1928 by the Committee on Manufacturing Risks and Special Hazards with the standard first adopted in 1929.

d. Final CO_2 concentrations of the original fire protection systems in the generator enclosure are from 30 percent to 34 percent. This concentration is hazardous to human occupants entering the enclosure after suppression activation.

e. The existing high-pressure CO_2 system functions similarly to those serving the oil storage and oil purification rooms except that there is no time delay (due to no personnel being present in the machinery) and there is also a generator differential auxiliary relay that alarms and discharges the suppression system in addition to the manual pull station(s) and manual CO_2 tank release(s). The heat detectors are located in the hot air ducts of the air coolers and accessible by access covers for inspection and testing. Device replacement may require removal of the air cooler depending on field conditions.

f. Early hydroelectric generators used generator winding insulation of thermoplastic materials such as asphalt, cloth ribbon, and polyester. Thermoplastic materials were considered highly combustible. As hydroelectric generators began having windings replaced, the generator winding insulation became thermoset materials such as fiberglass and epoxy resin. The assertion was that the thermoset insulated windings tend to be self-extinguishing when de-energized. Once the fire protection system is initiated, the generator is immediately de-energized and shut down.

g. The 2020 edition of NFPA 850 recommends generator fire protection for generator windings consisting of the earlier thermoplastic materials only. The annex of NFPA 850 continues to note that the operation of a fire protection system limits damage and reduces downtime regardless of winding material type where the generator cannot be de-energized. Mandatory generator fire protection requirements for USACE operated or owned facilities is contained in UFC 3-600-01 despite allowances contained in NFPA or other fire protection or insurance organizations.

h. Continued use of the existing CO_2-based fire suppression system is acceptable where fully functional and tested according to UFC 3-601-02.

i. Approved replacement systems are as listed in the most recent publication of UFC 3-600-01 section "Hydroelectric Generating Plants."

(1) Although high- and low-pressure CO_2 and clean agent suppression systems were listed as acceptable systems in 2018, only the UFC contains the latest acceptable system types.

(2) Replacement system designs must conform to UFC requirements for the year in which designed.

(3) Originally installed FACPs must be replaced.

(4) Originally installed fire detection and notification devices may be considered for re-use where network address module retrofitting is supported and permitted by UFC requirements.

(5) Systems may use portions of existing CO_2 piping network and must meet the most current codes as required by the UFC. Hydrostatic or pneumatic pipe testing is required for all newly installed and modified existing piping.

(6) Existing CO_2 storage tanks are prohibited for re-use and must be demolished.

(7) System flow calculations should be estimated during design.

(8) System flow calculations must be performed by the Contractor and reviewed for approval.

(9) System concentration for clean agent suppression must comply with UFC and NFPA requirements for the type of clean agent selected. The hold time duration for clean agent suppression must be 20 minutes without using an extended discharge. System concentration for CO_2 must be no less than 30 percent. The hold time duration for CO_2 must be 20 minutes without the use of an extended discharge.

(10) Any total flooding system concentration and hold time duration requirements specifically listed for hydroelectric generators in UFC 3-600-01 supersede values listed above.

(11) A generator fire protection system consisting of a single generator extinguishing source may provide protection for a maximum of four generators.

(12) Where a generator fire protection system has been interconnected to adjacent generator fire protection system(s), each interconnection point must be provided with a supervised, normally closed valve.

(13) Nominal CO_2 capacities must be adjusted to compensate for nozzle and tank ineffectiveness as prescribed by NFPA 12.

(14) System discharge validation should be performed for at least one of each system installed. A single or multiple generator fire protection system must have a single unit CO_2 or clean agent source discharged. The oxygen concentration must be sampled to determine agent concentration within the prescribed duration. Once initiated, suppression agent flow continues until fully discharged. Planning is required to contain suppression agent to protect personnel, property, and the environment.

21–9. Transformers

Install a fire suppression system protecting transformers as required by UFC 3-600-01.

a. USACE powerhouses contain transformers located in both interior and exterior locations. The transformers are used for both power distribution and facility power.

b. Indoor transformers of a size and capacity requiring fire suppression are often those providing facility power. Such transformers are typically installed in transformer vaults, which are dedicated rooms containing the transformer only. Existing transformers are often mineral oil-insulated and provided with a high-pressure CO_2 fire protection system similar to those installed for the protection of oil storage and oil filtration rooms and paint and flammable liquids storage rooms. Some plants have replaced original CO_2 fire suppression systems with water mist systems. Some plants have eliminated the requirement for fire suppression by replacing oil-insulated transformers with “dry type” containing no oil.

c. Main power transformers, also known as GSU transformers, are commonly located outdoors, on intake or tailrace decks, in the switchyard, or on an area adjoining the powerhouse upstream wall. The frequency of GSU transformer fires is extremely low. It is assumed that a transformer fire results in the total loss of the transformer and any adjacent power line support structures. GSU transformers typically contain large quantities of oil and, when located close to structures and equipment, present a high hazard. A means of protection through physical distancing, fire barriers, or water spray is required to protect nearby transformers, equipment, and structures. Deluge systems providing water spray protection for GSU transformers were common. As originally constructed, numerous facilities failed to provide safe transformer spacing or protection by fire barriers or water spray systems.

d. Outdoor transformer containment and spill prevention must be evaluated when replacing or upgrading GSU transformers per UFC 3-600-01 and Chapter 29.

(1) Outdoor transformer secondary containment must be provided for transformers protected by water spray systems. Many facilities were originally constructed either without containment or with an insufficient volume of containment, and frequently drainage of the transformer area discharges to civil drainage and then the river when in the switchyard or directly to the river when on the intake/tailrace deck. Existing containment is sometimes shared or interconnected among several transformers.

(2) To limit fire spread, the transformer containment must not flow to or through the containment of another transformer. Individual transformer containment drain piping often terminates into a central location (such as a sump). Containment must meet all requirements for new construction. Existing containment may be modified or replaced.

e. Outdoor transformer active and passive fire protection must be evaluated when replacing or upgrading GSU transformers. Evaluation ensures that required protective features and systems are provided to protect the facility and other transformers from fire damage. Existing active and passive fire protection may be modified or replaced. The installed system must meet all requirements for new construction.

f. Outdoor transformer deluge systems must be evaluated for suitability in meeting the most current requirements when replacing or upgrading GSU transformers. Replacement transformers not using oil as an insulator do not require the deluge water spray system, and only fire detection needs to be provided.

(1) Each transformer deluge system is designed for a specific transformer envelope and footprint. Changes to any dimensions of the transformer, including any transformer accessories or bushing elevations or locations, require a new nozzle layout and a new hydraulic analysis. Increases in transformer size often require a greater density of water spray and increases the amount of waterflow required at the transformer. The increased water demand potentially exceeds the existing pump capacity and possibly requires increased pipe sizes.

(2) Along with a major revision of the hydraulic components, the system control and power sources must be investigated and modernized as applicable to current standards. Often the pumps used on transformer deluge systems do not contain pumps and controllers listed for fire protection usage. All items that are not listed for fire protection use and do not meet current requirements must be replaced.

(3) Oil-filled breakers replaced with breakers containing no insulating oil require no sprinkler protection.

g. Outdoor transformer fires are best handled through a combination of automatic water spray systems and by trained firefighters using hoses at safe distances. An ideal fire event is one in which the transformer fire is contained and extinguished in one hour or less. Uncontrolled transformer fires have been documented to last from eight hours to as much as three days.

h. Water supplies must be dedicated for fire suppression water only. Washdown connections must not be contained on a dedicated water supply for fire protection.

i. Continued use of existing transformer deluge fire suppression systems is acceptable where fully functional and tested according to UFC 3-601-02.

j. Requirements for replacement systems are as listed in the most recent publication of UFC 3-600-01 section “Hydroelectric Generating Plants.”

(1) Although water spray was the only acceptable system in 2018, only the UFC contains the latest acceptable system types.

(2) Replacement system designs must conform to UFC requirements for the year in which designed.

(3) Originally installed FACPs must be replaced.

(4) System discharge validation should be performed.

21–10. Fire Alarm Control Panels and Units

Fire alarm controls are now microprocessor based and commercial off-the-shelf products often designated as FACUs. Modern FACUs are networkable and may contain hundreds of I/O points to monitor and control hundreds of attached devices.

a. Most hydroelectric facilities contain legacy FACPs for each fire protection system and sometimes a legacy FACP for the office spaces or other administrative areas.

b. Some facilities are being furnished with facility-wide FACUs to provide fire detection and mass notification throughout the entire facility. The generation system equipment (generators, storage and filtration rooms, transformers) FACPs may be replaced and integrated with the new facility FACP, or they may merely annunciate a discharge and not otherwise communicate.

c. Replacement fire protection systems have introduced modern FACUs into existing facilities such that there is a mix of legacy FACPs and modern FACUs and devices. Several individual hydroelectric facilities, Districts, and Divisions have begun working on standard system architecture schemes regarding an overall facility FACU that integrates with the generation equipment original FACPs or any modernized FACUs.

(1) All FACU systems must meet the requirements of UFC 3-600-01 and UFC 4-02101.

(2) Replacement system designs must conform to UFC requirements for the year in which designed.

21–11. Portable Fire Extinguishers

Portable handheld extinguishers provide fire protection for powerhouse hazards other than those protected by automatic fire suppression systems. Portable extinguishers should be provided in locations according to NFPA 10 except where prohibited or restricted by UFC 3-600-01. Portable extinguishers with the extinguishant type recommended for the anticipated hazard should be provided.

a. Break rooms and business occupancies should contain wet chemical or other portable handheld extinguishers suitable for combined Class A, combustible materials and Class F, cooking oils fires.

b. Residue-free extinguishers are recommended for use on Class E energized electrical equipment fires, and Class B flammable liquid fires of oil or solvents. CO_2 is not preferred and when used, is limited by UFC 3-600-01 for specific room or floor areas where asphyxiation concerns prohibit its use.

21–12. Detections

a. *Thermal Detectors*. Thermal detectors are best suited for locations within equipment such as generators or near flammable fluids.

b. *Ionization Detectors*. Ionization detectors are best suited for gases given off by overheating, such as electrical cables or a smoldering fire. Location near arc-producing equipment should be avoided. They are not suited for activating CO_2 systems.

c. *Photoelectric Detectors*. Photoelectric detectors are best suited for the particles given off by an open fire as caused by a short circuit in electrical cables. Their use in staggered locations with ionization detectors along a cable tray installation provides earliest detection.

d. *Location*. Detectors should be located at or near the probable fire sources such as near cable trays or in the path of heating and ventilating air movement. In areas where combustible materials are not normally present, such as lower inspection galleries, no coverage may be appropriate.

e. *Reliable Detection*. The earliest “reliable” detection is required. The detector type(s), location, and adjustment should be carefully considered. The detector sensitivity adjustment should be adjusted to eliminate all false alarms. A fire detector system should be provided in the cable gallery and spreading rooms of all powerhouses.

f. *Alarm System*. The power plant annunciation and, if applicable, the remote alarm system, should be used to monitor the fire detection alarms. An alarm system should be provided for each area. Properly applied, these systems provide more reliable and useful alarm data than the alarm monitor specified in the fire codes.

21–13. Isolation and Fire and Smoke Control

a. Smoke inhalation is one of the major causes for loss of life during a fire. The toxic fumes from a minor fire could require total evacuation of the powerhouse. Many of the existing heating, ventilating, and air conditioning systems contribute to spreading the smoke as they encompass the entire powerhouse or have a vertical zone composed of several floors. The fire area should be isolated by shutting down the ventilating system or exhausting the air to the outside where feasible to prevent the spread of smoke and to provide visibility for firefighting re-entry to the area. In most cases, the available oxygen is sufficient to support combustion, and little can be gained by not exhausting the smoke. Smoke and fire isolation should be provided in areas where isolation can provide a real benefit. Smoke migration may be controlled and managed through smoke barriers, partitions, dampers, and exhaust systems.

b. The requirements for firestopping is driven by facility fire barrier ratings. Rated fire barriers serve to compartmentalize hazards within the facility. Firestopping is a material or device installed to resist the passage of flame and heat through penetrations (a firestop) of a fire barrier. Firestopping must be provided where conduit, cable trays, pipes, or any other utilities pass through floors or walls rated as a fire barrier. Firestopping includes the following:

(1) The filling of voids created when fire-rated assemblies are penetrated, either partially or totally, by various building components and elements (such as pipes, ducts, conduits).

(2) The blocking-off of internal spaces within fire rated assemblies to limit the spread of fire within the assembly.

(3) The special connection required at the interface of a fire-rated assembly and other assemblies of the building (such as the floor/ceiling connections to a curtain wall assembly).

c. An HVAC system using outside makeup air solely dedicated for the control room should be provided to maintain isolation and smoke control. The HVAC system should be capable of pressurizing the control room with outside air during a fire alarm to prevent smoke infiltration. Stairways in staffed powerhouses that are used for emergency access and egress should be pressurized with outside air according to UFC and American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE) recommendations.

Chapter 22
Piping

22–1. General

The provisions of this chapter are applicable to all equipment and systems covered in this manual, wherever piping is required. The design considerations noted in the following paragraphs are those more frequently encountered in the design of powerhouse systems but are not intended as a complete listing. Other factors pertinent to the cost, life, and utility of piping in each particular powerhouse should also receive proper consideration in the design and design analysis.

a. *Design Analysis*. A design analysis should be prepared for each piping system. Include criteria, system assumptions, flow requirements, velocities, heads, losses, pipe sizing and materials, pump requirements, routing considerations, expansion and contraction of piping and structure, expansion joint requirements, support and anchor loadings and selections, and other factors considered during system design.

b. *Design Precision*. Caution and judgment are essential in applying factors and criteria available to ensure a satisfactory and economical design. The extent and degree of precision in design analysis should be consistent with the assumptions and other information available. For example, during initial powerhouse construction, quantities or flow rates are often based on rather rough assumptions, and where this is true, a brief and approximate analysis with conservative pipe sizing should be the rule. Complex and extensive systems with well-verified assumptions warrant more detailed and exact analysis to match pipe sizes as near as possible to requirements.

c. *Hydraulic Piping*.

(1) Piping for high-pressure, hydraulic-operating systems is specialty piping and discussed separately within their respective hydraulic equipment chapters.

(2) UFGS 35 05 40 14 10 covers piping requirements for hydraulic systems.

22–2. Guide Specifications and References

UFGS 40 05 13 should be used when developing specifications for piping systems. While there are many more types piping systems than what is used in a powerhouse, it can be tailored to suit. Generally, there is no need to deviate from the piping systems provided in the specifications. Take care when making any deviations. Additionally, ASME B31.1 provides guidance for piping systems in power applications.

22–3. Non-Metallic Piping

Previous versions of this manual have allowed non-metallic piping only in specific areas where the use of metallic piping is not feasible or normally used, such as drains for battery rooms. As such, at the time of this publishing, USACE has minimal experience and knowledge regarding the long-term feasibility, reliability, and life cycle cost of such piping systems in a hydroelectric powerhouse application when used for more general-purpose service such as cooling water or oil transfer.

a. It is recognized that in certain applications, non-metallic piping has certain advantages over metallic piping such as reduced material and installation cost, ease of installation, and corrosion resistance. As such, installation of non-metallic piping will be considered on a case-by-case basis if it conforms to the following requirements, which are in addition to all other piping requirements in this manual.

(1) All proposed or new non-metallic piping installations that are not covered by the material schedule in Table 22–1 (at the end of this chapter) and are covered by the scope of this EM must be reviewed by and approved by the HDC. The justification for using non-metallic piping should be consistent with the requirements listed in paragraph 22–5c.

(2) All non-metallic piping materials and installation must be consistent with ASME B31.1 and any other applicable codes such as NFPA or ASHRAE requirements.

(3) Polyvinyl chloride (PVC) piping is not allowed (except as shown in Table 22–1), regardless of whether the material is acceptable per applicable codes and standards. PVC piping has an unpredictable brittle failure mode that is not acceptable for the critical powerhouse systems. Additionally, if combusted, the fumes from PVC piping are particularly toxic compared to other non-metallic pipe materials.

(4) Non-metallic piping should be considered only on piping systems where the maximum working pressure is 100 psi (689 kPa) or less.

(5) Regardless of any other requirements, non-metallic piping is not allowed in the following locations due to a potential risk of a fire that could compromise non-metallic piping:

(a) Within the envelope of the rotating components of the generator unit, including but not necessarily limited to the rotating exciter housing, generator air housing, turbine pit, and headcover.

(b) In an oil storage room or any other spaces that store large quantities of flammable substances.

(c) In a gallery shared with electrical cabling (excluding cable in conduit) carrying power at a voltage higher than 480V.

(6) Non-metallic piping must be rigid and not soft or flexible (such as cross-linked polyethylene (PEX) piping commonly used on modern home plumbing).

b. If a non-metallic piping system is to be installed, the following should be considered during the design:

(1) Non-metallic piping systems generally require different spacing of pipe supports when compared to metallic piping systems due to the lower material stiffness of non-metallic pipe. If both types of piping are installed on the same pipe support system, then the spacing of such supports must be per the most stringent requirements.

(2) Non-metallic piping materials have to potential to sag or creep under their own filled weight, especially when subject to elevated temperatures. If the non-metallic pipe will carry warm or hot fluids, give special consideration to the thermal properties of the material chosen.

(3) Non-metallic material may be more susceptible to damage and failure due to external impact. Installations of non-metallic piping should be located to minimize the risk of impact, especially if motorized equipment is used in the area.

(4) Valves and inline appurtenances may not be available in the same material or end fitting as the rest of the non-metallic piping system. When dissimilar materials or fittings are used, ensure that they are compatible with the service and rest of the non-metallic piping system.

(5) Some non-metallic materials can be damaged by exposure to UV light. Installation locations and potential for UV exposure should be considered when selecting a non-metallic piping material and whether it is appropriate for the application.

22–4. Pipe Sizing

The following factors should be considered in determining suitable pipe sizes. Most of these are interactive in their effect on pipe size, and care in selecting the critical factor is essential.

a. Velocity.

(1) Velocity is typically a limiting factor only when erosion or cavitation would cause premature failure, noise, or thrust loading supports could be a problem, or, in the case of pipe used to transport fish or other materials, velocities are determined by other than piping considerations.

(2) Even when these limiting factors appear to apply, full consideration should be given to whether the limiting velocity is normal, infrequent, or temporary. An infrequent or temporary eroding velocity may well be justified in the interest of overall economy.

(3) For waterlines, velocities in the range of 8 to 12 fps (2.4 to 3.7 mps) are usually considered reasonable, but there is often good justification for higher or lower velocities. Copper waterline velocities should not exceed 7 fps continuously.

b. Pressure Loss.

(1) Pressure loss is often a limiting factor on pipe sizing when a fixed-gravity head is available or where the pipe is a minor part of a pumped system with the pump head determined by other major requirements.

(2) Average pressure loss computations should be based on moderately corroded pipe.

c. Pumping Cost. Pumping cost can be a significant factor in sizing pipe and requires careful analysis for extensive systems with high-use factors, both in energy cost and connected electrical load.

d. Corrosion Allowance. Allowance for restriction and increased pressure loss due to corrosion or mineral deposits is necessary, depending largely on pipe material and water chemistry. For steel pipe under average water conditions, a reduction in cross-sectional area of 15 percent is a suitable corrosion allowance.

e. Code Requirements. For piping systems covered by national or state building or plumbing codes, comply with all code requirements for minimum pipe sizes.

f. Previous Projects. Previous installations of similar systems can be a valuable guide in selecting pipe sizes, particularly when complete design analysis along with good service records are available.

g. Other Factors.

(1) *Equipment Connection Sizes*. These sizes are generally significant only for short runs of connecting piping.

(2) *Mechanical Strength*. When the pipe is small, consider where shock conditions could disturb pipe alignment. It can be more satisfactory to use a larger size pipe than to provide the additional supports for a very small pipe.

(3) *Temperature*. Using copper and galvanized steel for hot water in the 140 – 170 °F (60 °C – 76.7 °C) range on a continuous basis should be avoided.

h. *Precautions*.

(1) *Equipment Demand Forecasts*. Where sizing is based on advance equipment demand estimates, the analysis should so note, and office procedures should provide rechecking analysis against contract figures.

(2) *Coordination*. Much of the information on which pipe sizing is based comes from equipment supplier representatives, other engineering disciplines, and operation sources. Many costly design changes, change orders, and poor operating conditions have resulted from this exchange of information. It is the design engineer's responsibility to ask the right questions, make sure the listener understands the purpose of the question, and verify, reverify, and coordinate answers from all available sources.

(3) *Plant Expansion*. Allowance in pipe sizing for possible plant expansion is often warranted, particularly in embedded piping.

22–5. Materials

a. A material schedule with recommended materials for all standard powerhouse applications is included in Table 22–1.

b. To apply the material schedule, pipe wall thickness, fitting ratings, and valve ratings should be verified for each application. The possibilities of unusual pressure or shock possibilities, which could occur from mis-operation, high pool or tailwaters, or equipment changes, warrant particular attention. The existence of unusual corrosive characteristics of the fluid being handled should be investigated, and material adjustments justified accordingly.

c. If a deviation from the material schedule is required by a specific design, the following factors should be considered when determining if the deviation is acceptable. The design documentation report should include justification for deviations, and advance consultation with review offices is warranted, particularly in the case of new products:

(1) Procurement cost.
(2) Installation cost.
(3) Replacement cost.
(4) Service life.
(5) Normal availability.
(6) Maintenance.
(7) Appearance.
(8) Reliability.

d. If a new material that lacks a comprehensive experience record is proposed for a piping application, risk can be reduced, and experience can be gained by first performing a limited trial. The trial should be applied in a non-critical application.

22–6. Routing

a. *Embedded Versus Exposed*.

(1) Exposed piping is generally preferred, although it is typically not practicable to run drainage and vent lines exposed.

(2) Embedded piping has several inherent problems and should be avoided wherever practicable. Some noted problems with embedded piping are:

(a) Proper placement during construction is difficult to enforce.

(b) Damage from aggregate in the concrete may go undetected.

(c) Rupture of the pipe and filling with concrete occasionally occurs.

(d) It is difficult to obtain the necessary flexibility when piping crosses dam contraction joints.

(e) Corrosion, particularly near the point of emergence from concrete, is impossible to completely monitor or control.

b. *Routing Considerations*.

(1) Most exposed piping is generally placed in galleries, vertical pipe chases, and covered pipe trenches. Obtaining adequate space in these areas is often difficult and requires early planning to avoid later compromises in good O&M. Space concerns are especially true when additional pipe services are added to or modified within an existing gallery.

(2) Blockouts are usually preferred over sleeves since they permit more flexibility in modifying the piping arrangement during design and construction, expedite installation, and provide access for future replacement and/or repair.

(3) Preferred routing of piping should be developed as soon as equipment locations and layouts are determined. Use the preferred routing for requesting the necessary structural and architectural provisions.

(4) Routing must consider the requirements of NFPA 70 that define dedicated equipment spaces for electrical equipment. No piping should be located within this zone and should be routed around or away from equipment. If it is not possible to route pipe away from the defined zone, provide drip pans or other means of secondary containment to prevent fluid due to leaks or condensation from contacting the electrical equipment.

(5) Piping should be routed at least 3 ft (.9 m) from parallel runs of cable or bus to avoid induction heating of the pipe.

(6) The following factors enter into optimum routing and should receive continued consideration during the design:

(a) Dismantling, assembly, and maintenance including provisions for flushing.

(b) Valve maintenance and replacement.

(c) Supports.

(d) Draining and cleanouts.

(e) Provisions of sleeves and blockouts through concrete walls, floors, and columns.

(f) Length of lines.

(g) Number of direction changes.

(h) Insulation.

(i) Expansion.

(j) Sound.

(k) Line failure.

(l) Corrosion.

(m) Leakage.

(n) Condensation.

(o) Appearance.

(p) Coordination with electrical and structural requirements.

22–7. Pipe Supports and Anchors

a. Standards. Pipe supports and anchors should be designed, manufactured, and installed according to Manufacturers Standardization Society (MSS) SP-58 unless otherwise modified by this manual.

b. General Requirements.

(1) Supports and anchors may be separate units or may be combined in single units. Loadings are normally quite readily determined, and commercial units with established load ratings should be used for most applications.

(2) Pipe supports that support multiple lines should be configured to provide space for servicing each individual line without having to disturb adjacent lines.

(3) Where several pipes are to be mounted on one series of supports, spacing and load ratings should be as determined for the line with the most stringent requirements.

(4) Supports at branches should be considered for required expansion in both lines.

(5) Consider all possibilities for longitudinal forces because of valve operation at changes in direction, including safety and relief valves.

(6) All guide-type supports should provide free longitudinal movement of lines. On the U-bolt type, two nuts, one on each face of the supporting member to ensure a proper clearance, are required.

(7) Lock washers or double nuts should be used on all supports to avoid loosening from normal powerhouse vibration.

(8) Supports for copper lines should be copper plated, or the dissimilar metals isolated by a nonconducting medium such as electrical insulating tape.

c. Seismic Considerations. Seismic restraints and bracing may be required for new or modified piping. Bracing requirements depend on pipe size and the seismic zone in which the project is located. The piping designer should coordinate with the structural designer to determine the seismic restraint and bracing requirements.

d. Pipe Anchors.

(1) In horizontal lines, normally locate anchors approximately midway between expansion joints or loops. In longitudinal galleries, this usually results in anchors located near the center of each bay.

(2) In vertical lines, locate anchors at upper (highest elevation) ends when practical to minimize the required number of guides.

(3) Friction in sleeve-type expansion joints should be considered in anchor design.

(4) Anchor design should provide for forces imposed during testing and any unusual temperature conditions during construction.

22–8. Pipe Joints

The preferred type of joints of each piping system are listed in Table 22–1.

a. Location. Most joint locations are determined by available pipe lengths, the requirements for fittings, valves, and connected equipment, fabrication process, and installation requirements. In addition, the following should be provided:

(1) Union or flanged joints in all steel pipes should be downstream from valves.

(2) Exposed sleeve-type joints are adjacent to the point at which embedded piping is continued with exposed piping.

(3) Sleeve-type joints should generally be provided where piping connects with pumps or other equipment, unless the piping involved is small and obviously flexible enough to eliminate concern for vibration effects and strain due to misalignment. Vibration and strain effects should be considered both on piping and the connection equipment.

(4) Two sleeve-type couplings should be provided where embedded piping passes through valve pits (one on each additional line that may enter the valve pit).

(5) Sleeve, U-bends, or bellows-type flexible joints should be provided in exposed piping at or near contraction joints.

b. Insulating (Dielectric) Joints. Provide insulating (dielectric) joints or connections at the following locations:

(1) Connections between lines involving dissimilar metals.

(2) Between ferrous pipelines exposed in the powerhouse that remains buried in soil outside. Fittings should be located immediately inside of the powerhouse wall and precautions should be taken to assure that the pipes are isolated from the copper ground mat.

22–9. Expansion Joints

Provide expansion joints to allow pipe system movement such as thermal expansion, and to accommodate structural displacement at contraction joints.

a. Types.

(1) *Flexible Element*. Flexible element-type joints are available as catalog items. These joints have the capability for good service under severe conditions within their capabilities. Their principal advantages over sleeve-type couplings are freedom from leakage as long as they remain intact, lesser frictional forces, and the ability to accept greater misalignment, except torsional. Their disadvantages are the necessity for immediate replacement in case of failure and a lack of a recognized specification standard. Where predictably ideal design conditions can be obtained and maintained, their use can be justified.

(2) *Sleeve Type*. Sleeve-type joints are well suited for expansion and contraction, as well as torsional displacement, but are not suitable for radial misalignment and accommodate angular misalignment only to a very limited degree before axial displacement forces become unpredictable. All sizes are commercially available and should be applied according to their limitations. Two joints in close proximity on the same line can be used to provide for some radial displacement.

(3) *U-Bends* (expansion loops). U-bends are an excellent type of joint for all movements in piping and are trouble free when properly designed and installed. Space considerations are often a problem in powerhouse application of U-bends, and their cost is usually higher than other types of flexible joints. Their use has generally been confined to long, high-pressure, hydraulic oil headers in galleries. U-bends are commercially available and should be specified according to their catalog ratings.

b. *Location*.

(1) Expansion joints and loops are typically placed at the building contraction joints, but it is acceptable to provide them at other locations if they are more convenient for assembly and disassembly.

(2) A guide spool should be located close to and on each side of expansion joints and loops.

22–10. Valving

a. *General*.

(1) Valves should be provided as required for control (open-closed-modulating); isolating; bypassing; preventing backflow; preventing overpressure; and in many cases, where not an actual requirement for convenience of O&M.

(2) For maintenance purposes, design consideration should be given to minimizing the number of types of valves in a particular powerhouse.

(3) Back-seating valves or other types permitting repacking under pressure should generally be provided.

(4) Valves should be provided with means to lock the valve in the fully opened or closed position so that hazardous energy control program measures can be installed.

(5) Wherever possible, valves should be of the type that can be disassembled without disturbing adjacent piping, or equipped with end connections that allow easy disassembly (flanges). For other installations such as soldered-end or socket weld-end valves, provide dismantling joints nearby so that disturbance of the pipeline is minimized in the event a valve needs to be replaced.

b. *Location*. Whenever practical, valves should be located for convenient access by personnel. Considerations include elevation, orientation, and obstruction by other equipment. If convenient access is not practicable, they should generally be provided with remote control unless their only use is a very infrequent noncritical maintenance operation.

c. *Orientation*. Valves should be oriented so that personnel can easily operate the valve, visually verify its position, and install lockout/tagout equipment when required.

d. *Valve Types and Selection*. The following articles cover the main types of valves used in general water, oil, and air process piping within the powerhouse. This list is not comprehensive of all valves encountered within the powerhouse and does not cover special application valves such as those used in high-pressure hydraulic applications. For penstock shutoff valves, see Chapter 19. Wherever possible, valve types and specifications should be per UFGS 40 05 13 and materials for valve bodies should match the pipeline materials.

(1) *Gate Valves*. Gate valves fulfill the bulk of the requirements for non-modulating control valves and are the preferred type in larger diameters (greater than 6 in.) where ball valves are not economical or practical. Rising stem, single-wedge-type valves should be used unless space does not permit a rising stem. In those special applications, non-rising stem gate valves with indicators can be used. However, the operating disadvantages of having the screw threads in the contents of the pipe should be considered.

(2) *Ball Valves*. Ball valves are the preferred type of valve for non-modulating applications in diameters less than or equal to 6 in. While ball valves are generally

available in larger sizes, they are not typically the best economical choice for the application. Ball valves offer tight shutoff, quick operation, and relatively easy maintenance. Generally, ball valves should be full-ported and equipped with non-metallic seats.

(3) *Globe Valves* (including angle valves). Globe valves are the preferred valve type for modulating applications. They should also be used in critical drop-tight shutoff applications.

(4) *Plug Valves*. Plug valves may be used for applications where operation is infrequent, a relatively fixed modulation is required, or in some cases, where quick operation is a requirement. They have the disadvantages of a tendency to get frozen in a particular setting, developing small seepage leaks, and requiring lubrication in some applications, so careful consideration is necessary as to the actual overall benefits of their use.

(5) *Butterfly Valves*. Butterfly valves of the rubber-seated type offer significant cost advantages for some low-pressure, larger size applications. In some cases, their relatively low operating forces permit elimination of powered operators. Their primary use is for non-modulating applications, but butterfly valves may be used to modulate flow under certain circumstances: only through disc opening angles of 45 to 90 degrees.

(6) *Check Valves*. Conventional ball check, lift check, and swing check valves are all used regularly in powerhouse piping. Applications involving frequent flow reversals should generally be of the non-slam type. Some applications requiring low-pressure loss and minimum shock can justify selection of one of several patented “silent” check valves. Note that check valves are insufficient for the purpose of isolating equipment. For example, high-velocity oil flushing on a drainage line with only a check valve should not be performed without first installing an isolation valve (such as a ball valve).

(7) *Pressure-Reducing and Relief Valves*.

(a) When pressure-reducing valves are required to maintain a lower pressure system supplied by a higher pressure source, the lower pressure side should be further protected by one or more relief valves.

(b) A slightly undersized relief valve is preferable to an oversized valve to minimize erosion due to near shutoff operation.

(c) A manual bypass around the pressure-reducing valve is permissible; however, the maximum flow capacity of the bypass should be less than the relief capacity of the low-pressure system.

(d) A pressure gauge should be provided on the low-pressure system.

(e) The designer should be aware that pressure-reducing valves as well as relief valves are subject to wear and malfunctions, and great care is essential in their application, particularly in systems with maximum to zero flow requirements. Where the pressure differential is sufficient to jeopardize plant operation or safety, a positive standpipe overflow relief system or an alternate low-pressure source is preferable.

22–11. Painting and Coating

a. The exterior surfaces of ferrous piping should be protected by a paint or coating system. Generally, the interior surfaces of the piping are not painted or otherwise coated. Non-ferrous piping is typically left un-painted.

b. The painting of piping is covered in EM 1110-2-3400. UFGS specification section 09 97 02 should be used to specify the paint systems and application procedures. For most powerhouse piping, any of the paint systems suitable for atmospheric exposure are acceptable.

c. Paint top-coat color should be determined based on the site-specific requirements and any labeling or color scheme employed by the operating project.

d. Galvanized piping is acceptable, provided the exterior finish color is acceptable to the site. Life cycle maintenance of the galvanized coating should be evaluated when determining whether it is the appropriate coating for the application. Galvanized piping installed in areas subject to high levels of moisture or condensation may need additional painting to protect the pipe.

e. The cost of painting and maintenance is affected by pipe material, routing, and mounting and should be considered during design.

22–12. Insulation

a. Insulation impedes the regular inspection of the condition of the piping system. As such, avoid insulating pipes whenever possible.

b. Insulation should be provided for HVAC piping as required or recommended by applicable codes and standards.

c. Insulation for freeze protection is generally not required for pipe systems contained within the powerhouse as temperatures remain above freezing. Wherever practicable, for water carrying pipe located exterior to the powerhouse, such as drains, freeze protection should be accomplished by protected routing of the lines or planned draining of lines in cold weather. Where this is not practicable, insulation (plus heating if necessary) should be provided.

d. While previous versions of this manual recommended installing insulation on pipe to prevent condensation from dripping on electrical equipment, per requirements elsewhere in this chapter, it is preferred to avoid this situation altogether by routing piping away from electrical equipment or providing alternative means for preventing moisture from contacting electrical equipment.

e. Insulating pipe in galleries and similar spaces to reduce condensation is generally not required as condensation and high levels of moisture is typically not a problem for those spaces. If significant condensation is expected, apply a coating system that is more durable in a high-moisture environment.

f. Elevated temperatures and air flow in the generator housing during generation keep condensation from forming or accumulating on heat exchangers and cooling water piping. Condensation can form on cooling water piping when units are shut down for extended time, the cooling water is left on, and unit space heaters cannot keep the ambient temperature sufficiently high. While insulation has been installed at some plants to reduce condensation, shutting off cooling water flow or employing space heaters during these conditions is generally preferrable over installing pipe insulation.

22–13. Pipe Cleaning and Flushing

a. *Cleaning*.

(1) Prior to and during installation, all pipe, fittings, valves, and appurtenances should be cleaned of all foreign debris and substances.

(2) Take care to ensure that products used to clean pipelines will not contaminate or cause issues with the service of the pipe, such oil or toxic products in a water service pipe.

(3) Cleaning methods and products should not damage any coatings or surface finishes of the inner or outer diameter of the pipe.

b. *Flushing*.

(1) After installation, new and disturbed piping systems should be flushed to ensure all construction debris is removed.

(2) Recommended flushing velocities are a minimum of 15 fps. This may be difficult to achieve on larger diameter piping due to the large flow rate required and should be adjusted lower.

(3) For flushing new or disturbed portions of an existing pipe system, provisions should be included to not contaminate non disturbed portions of the system. Temporary inline strainers or filters should be used to catch debris.

(4) Flushing fluid should be selected based on the service of the pipeline and generally, the flushing fluid should match the service fluid. For oil-service lines, using the same type of oil for flushing operations as the service oil is especially important when considering potential compatibility issues.

(5) Flushing operations should be closed-loop and flushing fluid should be disposed of according to all applicable laws and regulations. If water is used, it should not be returned to the river unless it can be verified that the water is free of all reportable contaminations. Generally, it is not desirable to use oil from flushing operations as service oil as it may degrade or pick up contaminates that cannot be removed through filtering operations. See also Chapter 23.

22–14. Testing

a. As a general rule, all new or disturbed piping should be pressure tested according to ASME B31.1. For most piping, the test pressure is 1.5 times the maximum working pressure, except for drainage and waste piping, where a test pressure of 10 ft (3 m) of head should be used. The length of test should be sufficient to inspect all pipe, joints, valves, and appurtenances for leaks.

b. Water or the service fluid is the typical test fluid used for most piping systems. For pipe systems other than water service, consider the difficulty of removing all residual test fluid (drying the pipe). Generally, compressed air is not used for pressure testing due to safety concerns.

22–15. Piping System Identification

a. A pipe and valve identification system is required for each project. Existing operating projects should have an established labeling system and it should be used for all new and disturbed work within that project. All exposed piping and valves should be identified and labeled according to the established system.

b. Pipe labeling systems should adhere to ASME A13.1 as much as practicable, but at a minimum should clearly show the direction of flow, the fluid contained within the pipe, and the equipment serviced by that line. For example: LUBE OIL – THRUST BEARING – SUPPLY.

c. Each valve should be equipped with a tag that, at a minimum, contains the valve's unique designation. Check valves, relief valves, gauge cocks, receiver drain valves, and air-water service connection valves are not required to have a valve tag.

d. Valve handwheels, levers, or other type of manual operator should be color coded to indicate their normal operation position as follows:

(1) Red: normally closed.

(2) Green: normally open.

(3) Yellow: throttling or either open or closed.

Table 22–1
Piping materials and schedule

Service	Group	System	Max Pressure (psi)	Pipe	Joints	Fittings
Water Drains and Vents	A	Generator Cooling Service Raw Water Spiral Case Drain and Fill Draft Tube Drain Unwatering and Drainage Pump Discharge Turbine Glands Water Spray Fire Protection (upstream of deluge valve) Turbine Air Supply	125	3" Diameter and Smaller: Seamless stainless-steel tubing, Grade TP304/304L per ASTM A269 or Seamless copper tubing, Type K per ASTM B88. See Note 1 Larger Than 3" Diameter: Carbon steel pipe, Type S, Grade B per ASTM A53 Wall Thickness: See Note 2	Stainless Steel Tubing: Welded or compression fittings Copper Tubing: Soldered per ASME B31.1 or ASTM B828 Carbon Steel Pipe: Welding fittings or flanges per ASME B16.5. See Note 3	Stainless Steel Tubing: Two-ferrule compression fittings Grade TP304 or TP316 with Threads per ASME B1.1. See Note 4 Copper Tubing: Cast fittings per ASME B16.18 or wrought fittings per ASME B16.22. See Note 8 Carbon Steel Pipe: Butt-welding fittings per ASTM A105 or ASME B16.9 with thickness same as Pipe. See Note 5
	B	Potable Water	125	3" Diameter and Smaller: Seamless copper tubing, Type K per ASTM B88 Larger Than 3" Diameter: Galvanized carbon steel pipe, Grade B, Type E per ASTM A53, Schedule 40. See Note 6	Same as Group A	Same as Group A except that carbon steel pipe fittings are galvanized. See Note 6
	C	Water Spray Fire Protection (downstream of deluge valve)	150	Galvanized carbon steel pipe, Grade B, Type E per ASTM A53, Schedule 40. See Note 6	Smaller Than 3" Diameter: Threaded per ASME B1.20.1 3" Diameter and Larger: Welded	Smaller Than 3" Diameter: Galvanized malleable-iron per ASME B16.3, MSS SP-83, and ASME B16.39 3" Diameter and Larger: Same as Group A except galvanized. See Note 6

Service	Group	System	Max Pressure (psi)	Pipe	Joints	Fittings
	D	Air Condition Circulating Water (see Note 7)	20	Smaller Than 3" Diameter: Galvanized carbon steel pipe, Grade B, Type E per ASTM A53, Schedule 40 3" Diameter and Larger: Carbon steel pipe, Grade B, Type E per ASTM A53, Schedule 40	Smaller Than 3" Diameter: Threaded per ASME B1.20.1 3" Diameter and Larger: Welded	Smaller Than 3" Diameter: Same as Group C 3" Diameter and Larger: Same as Group A
	E	Building and Roof Drains Sanitary Drains and Vents Water Discharges		Exposed: Galvanized Carbon steel pipe, Grade B, Type S per ASTM A53 Buried and Embedded: Hubless cast iron per CISPI 301	Exposed: Threaded Buried and Embedded: Same as Pipe	Exposed: Cast iron, per ASME B16.4 Buried and embedded: Same as Pipe, per ASTM A888 See Notes 8 and 9
	F	Turbine Vacuum Breaker and Sump Vents		Carbon steel pipe, per ASTM A53. Schedule 80 See Note 10	Welded	Same as Group A
	G	Battery Room Drains		Exposed: PVC, Schedule 80, per ASTM D1785 or “Duriron,” “Corrosiron,” or Equal. Embedded: “Duriron,” “Corrosiron,” or Equal.	Same type and manufacturer as Pipe	Same type and manufacturer as Pipe
	H	Pressure Sewage	100	Exposed: Carbon steel, Schedule 80, per ASTM A53 Buried or Embedded: Ductile iron per ASTM A377	Exposed: Same as Group A Buried or Embedded: per AWWA C110/A21.10 and AWWA C111/A21.11	Exposed: Same as Group A Buried or Embedded: per AWWA C110/A21.10 and AWWA C111/A21.11
	I	Piezometer	125	Seamless copper tubing, Type K per ASTM B88	Soldered per ASME B31.1 or ASTM B828	Cast fittings per ASME B16.18 or wrought fittings per ASME B16.22. See Note 11

Service	Group	System	Max Pressure (psi)	Pipe	Joints	Fittings
Oil	K	Governor and Lubrication Oil Circuit Breaker and Transformer Oil Transformer Oil Transfer Systems See Note 12	150	Same as Group A. See Note 13	Same as Group A	Same as Group A
Air-Gas	M	Service Air Brake Air Draft Tube Depression Air Bubbler Air Lines	125	Same as Group B. See Note 14	Same as Group B	Same as Group B
	O	Governor Air (low pressure systems) Nitrogen	600	Galvanized steel, Schedule 80, per ASTM A105	Threaded per ASME B1.20.1	Smaller Than 2.5" Diameter: Galvanized malleable iron, 600 psi W.O.G. Min. per ASME B16.3 2.5" Diameter and Larger: Forge steel, 2000 psi W.O.G. per ASME B16.11
	P	Carbon Dioxide Clean Agent		See Note 15	See Note 15	See Note 15
	R	Governor Air (high-pressure systems)	1,100	Stainless steel, Schedule 40, Type 304 or 316 per ASTM A312	Welded	Stainless steel, socket weld, 2000 psi, per ASME B16.11
Misc.	S	Hypochlorite Solution		PVC, Schedule 80, per ASTM D1785	Same as Pipe	Same as Pipe

Service	Group	System	Max Pressure (psi)	Pipe	Joints	Fittings
	Y	Floatwells		Exposed: Same as Group B Embedded: See Note 16	Exposed: Same as Group B Embedded: Same as Pipe	Exposed: Same as Group B Embedded: Same as Pipe
	Z	Sleeves		Carbon steel, Schedule 40, per ASTM A53	None	None

Notes:

1. The stainless tubing system is typically preferred for all new installations or major rehabilitations where most of the piping is being replaced. The copper tubing system should be used when replacing small portions of an existing system and/or when water quality issues discourage the use of stainless steel.

2. Pipe and tube wall thickness should generally be consistent with ASME B31.1. For Nominal Pipe Size (NPS) 10 and smaller, Schedule 40 should be used. Pipe sized NPS 12 and greater may use Schedule 10 to be more economical. Embedded lines open to tailwater or forebay without extra provision for ready shut-off should be Schedule 80.

3. Flat-faced flanges are required when connecting to cast iron. In other connections, flat flanges with full face gaskets are preferred to raised face flanges.

4. Compression fitting nut, body, and ferrules should all be made from stainless steel. Also referred to as double-ferrule compression fittings. These fittings are often marketed under tradenames such as Swagelok or Parker A-Lok. While it is best to have all fittings from the same manufacturer for a new piping system, generally, the products from different manufacturers can be interchanged.

5. If the specified wall thickness is unavailable, use the next heavier available.

6. Welded galvanized pipe should normally be galvanized after fabrication.

7. Once through air conditioning equipment, use Group A.

8. Group A copper elbows and all Group E elbows should be long radius or long sweep.

9. In drain lines, use combination “y” and 1/8 bends wherever possible for branches from horizontal runs.

10. Embedded lines open to tailwater or forebay without external provisions for ready shut-off should be extra-heavy steel from the first valve.

11. Piezometer tubing embedded more than 6 in. may be Type K annealed with bent turns.

12. Hoses may be used for temporary connections for oil transfer operations. When hoses are used, hose construction must be compatible with the oil being transferred. Fittings can be threaded or quick-disconnect type, and should be made from stainless steel and crimp-on type compatible with the hose type. If threaded fittings are used, they should conform to ASME B1.20.7. Hose threads should have manufacturers tag showing thread specification.

13. For copper oil line, add separate group with required joints when temperature or pressure exceeds soft solder rating.

14. Use Group C between compressor and aftercooler for piping 2.5″ in diameter and smaller.

15. Refer to NFPA for requirements for piping used in CO_2 and clean agent fire suppression systems.

16. Previous versions of this table listed asbestos cement piping for embedded pipe. Existing embedded float well piping should be tested for asbestos prior to disturbing.

Chapter 23
Oil Systems

23–1. General

a. A minimum of two installed oil systems, governor-lubrication oil ("turbine oil") and insulating oil ("transformer oil" or "transil oil"), are required in most powerhouses. A powerhouse might have a third dedicated system for hydraulic intake gate cylinders. Other powerhouse oils that may be necessary are handled in portable containers and are not covered in this chapter. See also EM 1110-2-1424.

b. Unit lubrication and governor system designs, as well as storage and distribution systems, are based on using a common oil in USACE plants. This is not necessarily true for other powerhouses; some designs use one oil for the hydrodynamic bearings and another oil for the governor and its hydraulic control of the wicket gates and turbine blades (if applicable). Occasionally a higher viscosity grade of the same turbine oil is used in the hub of a Kaplan unit, for decreased leakage and improved boundary lubrication, or in a guide bearing as a troubleshooting measure to dampen vibrations.

c. All turbine oils used in a unit must be compatible with each other, unless the unit design allows complete separation of oils without mixing, and the powerhouse is designed and equipped to handle multiple turbine oils entirely separately. Compatibility is typically determined using ASTM D7155. See EM 1110-2-1424 for more information.

d. All systems should maintain complete separation of different types of oils, unless compatibility has been tested with satisfactory lab results and a displacement flushing procedure is in place for the shared piping or purifier. Design emphasis should provide maximum protection against misrouting and mixing of oils and fire hazards resulting from spillage. Separate piping systems should be provided to the extent possible for insulating oil for the transformers and circuit breakers to minimize the chance of mixing these oils.

e. Any rehabilitation work on oil systems must consider oil spill prevention, and should also consider oil accountability. Examples of oil spill prevention upgrades include containment for transformers, sealing concrete monolith joints that otherwise might be exposed to oil leaks, and diverting oily water to oil-water separators. Examples of oil accountability upgrades include installation of flowmeters on both the main supply and drain headers, installation of magnetostrictive or other highly accurate level sensors, as well as temperature sensors on tanks and sumps. See also Chapter 29.

23–2. System Requirements

a. *Governor-Lube Oil*. Turbine oil should last 20–30 years if kept cool, clean, dry, and uncontaminated. Plant-wide replacement of turbine oil may be advisable as part of a major rehabilitation project or if the oil has reached the end of its useful life, as evidenced by poor lab test results. A temporary measure for turbine oil with poor test results could be to replace a portion of the oil, also known as "sweeten" the oil, ensuring full compatibility. In addition to EM 1110-2-1424 and ASTM D4378, the following operations are normal system requirements:

(1) *Filling dirty/new oil storage tank from tank car or truck*.

(a) It is beneficial to have an oil/fill discharge cabinet in the erection bay such that the delivery or disposal truck can pull into the powerhouse over oil spill containment. Pumping oil from a truck or into a truck can take several hours. New oil might be delivered through a filtration cart with particle counter, in which case keeping the truck in a space that is 60 °F or greater is preferred, to improve filterability of the oil. New oil is typically dirty and requires purification before use.

(b) Consider space on the project for temporary storage of newly delivered oil still in the Contractor’s equipment with appropriate spill prevention measures in place. This allows sampling of the actual delivered oil for lab testing to check that it meets all specifications. Oil held in the Contractor’s tanks in “quarantine” pending lab test results can be readily removed by the Contractor if it fails. Oil that had already been pumped into Government tanks before it was found to not meet specifications presents more contractual difficulties, because the Contractor was not in control of the cleanliness or previous contents of Government tanks.

(2) *Moving oil from clean oil storage tank by either the purifier or transfer pump to the generator-turbine unit*. Some supply header pipes are full only during pumping operations, where others are held at pressure by oil stored in gravity tanks several feet above the header in elevation. If oil will be transferred directly from the clean oil storage tank without any removal of water content through the purifier on the way to the unit, consider a desiccant breather on the storage tank. Breathers might not be worth the trouble if safe access to change the desiccant is an issue, or if ingress of atmospheric moisture into the stored oil is minimal.

(3) *Draining or returning overflow oil from the generator-turbine unit to the dirty oil storage tank*. Varnish and sludge deposits are a common problem in the entire lubrication system, but especially in the drain header. Drainage headers tend to be dirtier both because the oil has been used, and because more particulates will drop out of slow-moving oil. It can take days for all the oil to reach the dirty tank, which is a complication for oil accountability measures.

(4) *Moving oil from either storage tank to a tank car or truck for disposal*. This operation can take several hours for tanks that store thousands of gallons.

(5) *Flushing*. For any plant where the lubrication system piping was not originally designed with loops (also known as “circuits”) for high-velocity hot oil flushing (HVOF), consider adding tees and ball valves during a refurbishment or prior to turbine oil replacement. Ensure positive isolation of units; drain lines were often designed with only check valves, which are not sufficient to isolate a running unit during HVOF. Beyond the main headers and branches, such as for individual bearing sumps, other methods (pressure wand, fill/drain, just wipe down) may be preferable, depending on system condition and compatibility of new oil.

(6) *Recirculating oil from any unit component through filtration cart and/or dehydrator and back to equipment*.

(a) It is desirable to have a permanent kidney-loop filtration unit on each governor sump, especially after conversion to a digital governor due to cleanliness requirements. In some cases, permanent kidney-loop filtration is desirable in additional locations, such as bearing sumps. Another alternative is a portable filtration cart, which can be used at each bearing sump without draining the unit.

(b) For plants without functional main lube oil supply/drain headers, the portable filtration cart and portable dehydrator are necessary.

(c) Various combinations of micron-sizes and filter media can be used successfully. Cellulose media has the benefits of capturing some amount of moisture and attracting varnish particles. Filter sizes below 3 microns absolute are typically not necessary or recommended.

(7) *Recirculating oil from any storage tank through purifier and back to the tank*. Often this is done with a positive displacement pump on the purification skid.

b. Insulating Oil.

(1) The systems for insulating oil were originally designed to perform essentially the same functions as for governor-lube oil above, with each operation relative to transformers or circuit breakers instead of generator-turbine units.

(2) Modern requirements for cleaning and drying insulating oil have made using original storage tanks and purifiers uncommon. More often, a specialized service truck with onboard purification systems is driven to the transformer location, where the oil is cleaned and dried in a kidney-loop fashion without draining the transformer. Transformer oil storage tanks can be kept for draining transformer oil in case of emergency or for discharge/disposal of transformer oil at the end of its useful life. Tanks that are free of polychlorinated biphenyls (PCBs) can also be recommissioned for use in the turbine/lube oil system.

(3) If original storage tanks and piping are used, the passage of oil from the tank through the piping back up to the transformer can cause the oil to be out of the modern stringent specifications for both cleanliness and water content. If original tanks and piping are used, consider a thorough HVOF of this equipment and refurbishing valves and seals according to manufacturer recommendations, to minimize contamination of the insulating oil. Also consider desiccant breathers on the tanks.

23–3. Oil Storage Room

a. Oil Containment Considerations. The oil storage room should be located at a low elevation in the powerhouse (for gravity return of oil), typically in mass concrete, with the floor several steps below the entrance level. The room should be designed to act as a sump, containing any oil that could spill from a tank without allowing passage to the river or to other areas of the powerhouse. When feasible, the sump volume should also be sufficient to contain all fire suppressant fluid that would be discharged into the room in case of fire. Sloping the floor to a small sump facilitates collection of small spills for accountability and cleanup.

b. Fire Protection Considerations. The storage of large quantities of oil, oil filtration, and processing equipment requires fire-resistant construction, fire detection and protection systems, and specialized egress. Originally constructed oil storage and oil filtration rooms were provided with fire protection systems meeting national fire codes. Best practice is to contain all oil handling equipment within the oil storage and oil purification rooms, as these spaces use fire protection systems to specifically detect and suppress oil fires. See also paragraph 21–6.

c. Purification. If separate oil storage and purification rooms are provided, the room requirements are similar. Note that even though the purifier does not contain much oil at any given time, containment should consider that oil can be pumped through from one of the large storage tanks.

23–4. Oil Storage Tanks

a. Capacity. Clean and dirty insulating oil tanks should each hold a minimum of 110 percent of the oil required to fill the largest transformer on the system. Clean and dirty governor-lube oil tanks should each hold a minimum of 110 percent of the oil required to fill the governor system and all the bearings of the largest generator-turbine unit.

b. Design. Storage tank design should conform to the applicable requirements of American Petroleum Institute (API) Standard 650, UL Standard 142, or ASME BPVC (15 psi [103 kPa] and over). Storage tank design should also conform to NFPA 30 Flammable and Combustible Liquids Code. Minimum wall thickness should be 6.4 mm (1/4 in.). Tanks should be provided with direct reading and/or magnetostrictive liquid-level gauges, and the interior finish should be an epoxy-based paint system. Tank replacement is rare, but occasionally a tank interior needs to be re-painted. To determine the type and configuration of tanks, consider the following:

(1) Shipping limitations.
(2) Shipping costs.
(3) Space and scheduling for field erection.
(4) Testing of field-erected tanks.
(5) Limitations on oil room configuration.
(6) Maintenance access.
(7) Seismic restraint requirements.

c. Cleaning. Cleaning oil tanks should be done with mechanical rather than chemical means if at all possible. If detergents or other chemical cleaners are required, perform a thorough flushing afterwards, such as by hand-held pressure wand over every oil-wetted surface in the tank. Flushing fluid can be a sacrificial quantity of the final oil to be stored in the tank, an unadditized mineral oil, or a very lightly additized transformer oil known to be compatible with the final oil. All flushing fluids should be sacrificial/disposed of after use.

23–5. Pumps

a. General. Oil system pumps should be the positive displacement type and should be provided with safety relief valves and high-temperature shutdown. Suction lift should not exceed 15 ft (4.5 m), and pump speed should be limited to 1,200 rpm. Control should be manual, but timer switches should be used to prevent continuous pump operation beyond the normal time required for each oil transfer. Pump capacity may be provided in single or duplex units, but if single, a standby pump for convenient exchange should be available.

b. *Dirty Oil Pumps*.

(1) *Waste Oil*. A pump should be provided to pump waste oil to a deck waste valve. Capacity should permit emptying the largest tank in approximately 8 hours or less. The pump should have a hose valve suction connection for the hose connecting to the insulating oil tank, governor-lube oil tank, or floor sump. A suction line filter is required to protect the pump from foreign material. Manual timer switches should be located in the oil room and at the deck valve.

(2) *Non-Gravity-Return Oil*. Projects where it is not feasible to return oil from generator-turbine bearings and governor to the dirty oil tank by gravity should have pumps for this service. The location will usually be in the turbine pit at each unit.

c. *Clean Oil Pumps*.

(1) *Governor-Lube Oil*. A governor-lube oil pump sized to fill the bearings and governor of the largest unit in approximately 8 hours or less should be installed in the oil storage room. An adjustable back pressure valve and the safety relief valve should bypass excess oil back to the clean governor-lube oil tank. The safety relief valve should be set to maximum system operating pressure, and the adjustable back pressure valve-to-pump rating but not higher than 95 percent of the safety relief valve setting. Manual timer switches should be located in the oil room and at each unit.

(2) *Insulating Oil*. The insulating oil pump should have approximately 105–110 percent of the capacity of the purifier to be used at the transformers. An adjustable back pressure valve and the safety relief valve should bypass excess oil back to the clean insulating oil tank. The safety relief valve should be set to maximum system operating pressure and the adjustable back pressure valve-to-pump rating, but not higher than 95 percent of the safety relief valve setting. Manual timer switches should be located in the oil room and at each deck valve.

23–6. Oil Piping

a. *General*. Refer to Chapter 22 for general piping considerations. Figure 23–1 and Figure 23–2 show schematics of typical governor-lubrication oil and transformer oil systems, respectively.

b. *Special Provisions*.

(1) Supply piping should be sized to deliver full pump flow to the most remote outlet without exceeding allowable tubing pressure.

(2) Return piping should be sized to drain the most remote transformer or generator-turbine-governor within 8 hours.

(3) Return lines should be routed to avoid air traps. Loops discharging to the bottom of tanks should be vented to the top of the tank.

(4) Provisions for a full flushing “loop” should be installed at the ends of the supply and drainage headers, and at the ends of supply and return line branches to each unit (or pair of units). One option is to pipe the full connection with isolation valves, such that there is a permanently installed piping connection between the supply header and the drainage header. Another option is to install tees with ball valves, with no actual piping connecting the supply header to the return header. A flushing Contractor then provides hose “jumper” connections between lines as needed during actual flushing operations. This might be preferred due to piping configuration or space constraints, or from an abundance of caution against accidental misrouting of oil.

(5) Normal overflows and leakage should generally drain by gravity to the dirty oil tank. Where this is not possible, an automatic float-operated pump and sump should be provided.

(6) The piping layout should provide for pipe drainage back to the tank wherever practicable.

(7) Pressure gauges with isolating cocks should be provided on the suction and discharge of each pump.

(8) Sampling cocks should be provided at bottom of tanks and at one-fourth points up to the top.

(9) Fixed piping connections are used for generator and turbine bearing sumps and governor tanks.

(10) Hose valves and hoses are used for connections to transformers and circuit breakers.

(11) The piping material schedule in Chapter 24 provides for Type K, hard-drawn copper tubing for oil system piping. Soft solder connections are normally satisfactory. Using any paste or tape, such as PTFE tape on threaded connections, is discouraged due to concerns of contaminating the oil.

(12) Overflow drains to the dirty oil tank should be installed without valves.

(13) Purifier hose connections should be provided in the oil storage room, transformer locations, and at generator-turbine unit components as needed.

23–7. Oil Purifiers

a. *General*. Each powerhouse must be provided with the means to remove particles and water from their oil. Carts with onboard particle counters and moisture saturation sensors are beneficial, though calibration (or periodic comparison with lab results) is needed. Portable purifiers are preferred. Larger plants might find it cost-effective to have both larger-capacity dedicated equipment in the purification room and smaller portable carts. This allows both efficient purification of oil when fully draining a unit, and good oil maintenance in the interim.

b. *Purifier Access*. Overall purifier dimensions, access doors and ramps, and elevator sizes must be coordinated in the early powerhouse planning to permit purifier access to the oil storage room, transformer locations, and purifier connections at generator-turbine units. Delivery of new purifiers might require using the overhead crane rather than the elevator.

c. *Governor-Lube Oil Purifier*. The main purifier for the powerhouse should be capable of processing oil with 1 percent water and 0.5 percent solids by volume to no more than 0.25 percent water and 0.02 percent solids, and remaining solids not exceeding 40 microns in size. The separated water should not contain more than 0.5 percent oil by volume. Purification should be attained in one pass. The purifier rating should provide purification of the dirty oil tank capacity within 8 hours (barring purifier size constraints). Purifier units should include required pumps, oil heaters, controls, and wheeler carriage.

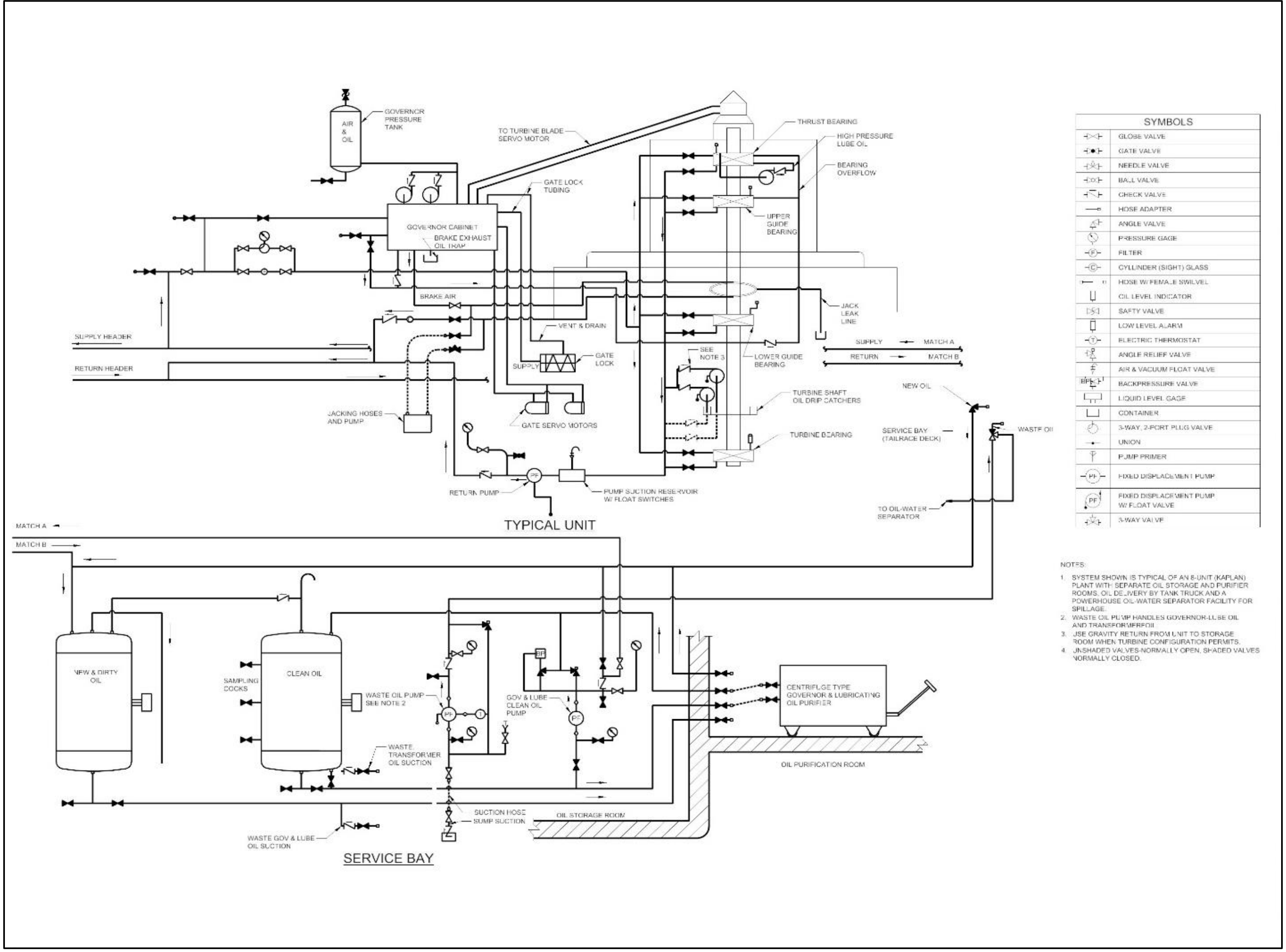
(1) *Dehydration*. A centrifuge is effective at removing large quantities of water and sediment. A coalescent-type purifier is also effective at removing free water. Water levels should be kept below 100–200 ppm.

(2) *Removal of Dissolved Water*. Equipment capable of removing dissolved water as well as free water is strongly recommended, because water that was dissolved in warm oil will come out of solution in cold oil, leading to rust and corrosion. Solubility of water in oil also depends on age and chemistry. Vacuum dehydrators effectively remove dissolved water once the bulk of the free water has already been removed. Sump or tank headspace dehumidifiers are another option to remove both free and dissolved water.

(3) *Filtration to Required Cleanliness*. Provide oil to the governor sump at 17/15/12 ISO cleanliness code if possible, because kidney-loop filters are typically sized to preserve oil cleanliness rather than remove large quantities of particles. It is not only digital governor proportional valves that benefit from clean oil, but all lubricated surfaces also undergo less wear with cleaner oil. The oil itself will last longer with fewer catalysts for oxidation.

(4) *Varnish Removal*. Depth cellulose filters in the governor kidney-loops can remove some varnish from the oil (and some free water also). More thorough varnish removal requires a system specifically tailored for that purpose, such as a balanced-charge agglomeration-type filter. Ideally, turbine oil is kept cool, clean, dry, and uncontaminated to the extent practical, and large quantities of varnish are not generated.

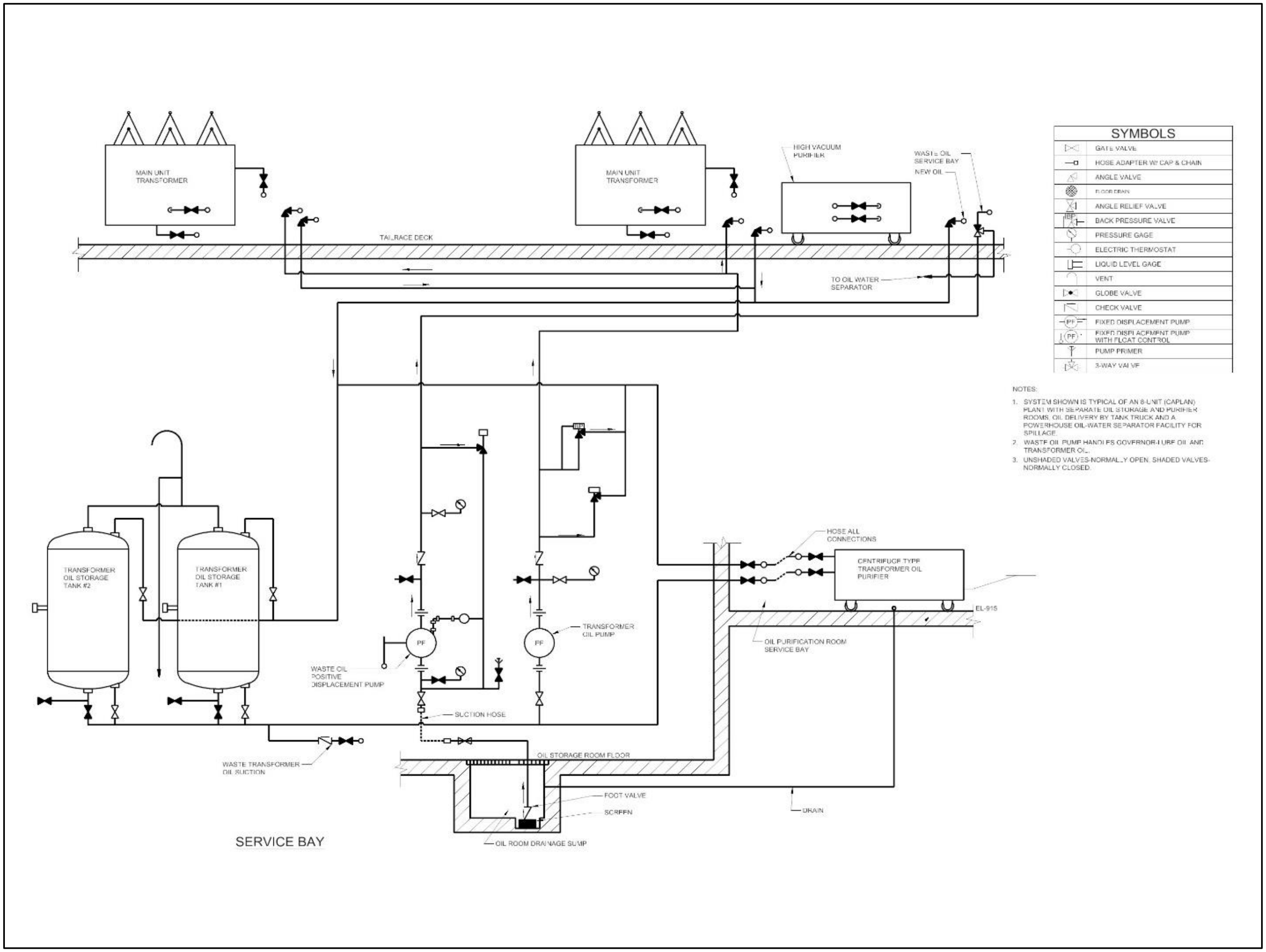
d. *Insulating Oil Purifier*. For plants using their own purifier for insulating oil instead of a specialized service truck, the insulating oil purifier must be designed so that the processed oil meets the transformer oil purity requirements. This normally consists of a filtration system and a high-vacuum purifier.



NOTES:

1. SYSTEM SHOWN IS TYPICAL OF AN 8-UNIT (KAPLAN) PLANT WITH SEPARATE OIL STORAGE AND PURIFIER ROOMS, OIL DELIVERY BY TANK TRUCK AND A POWERHOUSE OIL-WATER SEPARATOR FACILITY FOR SPILLAGE.
2. WASTE OIL PUMP HANDLES GOVERNOR-LUBE OIL AND TRANSFORMERFOIL
3. USE GRAVITY RETURN FROM UNIT TO STORAGE ROOM WHEN TURBINE CONFIGURATION PERMITS.
4. UNSHADED VALVES-NORMALLY OPEN, SHADED VALVES NORMALLY CLOSED.

Figure 23–1. Example governor–lubricating oil system schematic



NOTES:

1. SYSTEM SHOWN IS TYPICAL OF AN 8-UNIT (CAPLAN) PLANT WITH SEPARATE OIL STORAGE AND PURIFIER ROOMS, OIL DELIVERY BY TANK TRUCK AND A POWERHOUSE OIL-WATER SEPARATOR FACILITY FOR SPILLAGE.
2. WASTE OIL PUMP HANDLES GOVERNOR-LUBE OIL AND TRANSFORMER OIL.
3. UNSHADED VALVES-NORMALLY OPEN. SHADED VALVES-NORMALLY CLOSED.

Figure 23–2. Transformer oil system

Chapter 24
Water Supply Systems

24–1. General

a. The water supplies covered in this chapter provide water for the following systems:

(1) Generator air coolers and bearing coolers.

(2) Turbine bearing coolers, wearing rings, and glands.

(3) Transformer cooling.

(4) Fire protection.

(5) Potable water (domestic water).

(6) Air conditioning systems.

(7) Pump bearing pre-lube.

(8) Air compressors and aftercoolers.

(9) Deck washing.

b. The various requirements are divided into several powerhouse systems for convenience in coverage. However, powerhouse and project requirements, interconnection of systems, and suitable water sources vary from project to project, and the designer is required to apply the information noted to the best advantage for each particular powerhouse.

c. General piping requirements for all systems are covered in Chapter 22.

24–2. Water Quality

a. For new plants, water quality should be analyzed and compared to existing plants on the same stream. Where existing plants are remote or the project is on a previously undeveloped stream, a water analysis should determine the likelihood of corrosion or scale deposits and the need for additional treatment for the particular type of water usage.

b. For existing plants, it is important to note that water quality may change over time. Environmental or operational conditions may affect and change river or lake water temperatures, nutrient loads, debris, and silt loads. Wells may be affected by nearby development that occurred after initial project construction. These changes in water supply may affect and impact project operations and need to be considered for continuing project operations as well as future rehabilitations and investments.

24–3. Aquatic Invasive Species

a. Zebra mussels (Dreissena polymorpha) are expected to eventually infest all major freshwater bodies of the continental United States where environmental conditions (such as dissolved oxygen content, calcium content) are favorable.

b. The USBR Document Number Ecolab-FA981-2020-02 provides monitoring guidance for determining the presence or absence of zebra mussels and collection of information for detailed studies of zebra mussel populations.

c. USBR Report Number ST-2019-7136-01 provides control strategies for zebra mussel infestations of various hydropower plant components.

d. In a hydropower facility, all external and internal structures and equipment in continuous contact with raw water from the forebay or tailrace are vulnerable to fouling from zebra (and quagga) mussels. Vulnerable structures and equipment include, but are not limited to:

(1) Raw water piping.
(2) Generator cooling systems.
(3) Strainers, pumps, and valves.
(4) Trash racks.
(5) Intake/draft tube gates and bulkheads.
(6) Drainage and unwatering sumps.
(7) Drains, hatches, and covers.

e. Biofouling from zebra mussels and other invasive mollusks in powerhouse raw water systems may result in more frequent main unit outages and higher O&M burden due to equipment cleaning. The aggressiveness and duration of mollusk infestations are difficult to predict and vary greatly between powerhouses based on environmental conditions in the reservoir and the configuration of the powerhouse raw water system.

f. Given the correct environmental conditions, zebra mussel larvae can attach to most surfaces. However, zebra mussel larvae cannot attach to any surface where water flow velocities are above 6.5 fps (2 meters per second). When determining at-risk equipment for zebra mussel infestation, consider analyzing equipment to determine if water velocities in these areas are above this velocity threshold for attachment.

g. Where possible, equipment and systems at risk for zebra mussel infestation should be designed for simplified disassembly, inspection, and maintenance. For example, hinged manifold head covers on generator coolers facilitate cleaning, as do pipe cleanouts and wye fittings placed at regular intervals within the piping system.

h. Newly installed raw water strainers at USACE facilities at risk for zebra mussel infestation should be of the dual-basket, manually operated type. This allows strainer cleaning without a main unit outage as the flow of raw water can continue while the out of service strainer basket is removed and replaced. Strainer baskets should be made of stainless steel.

i. Where possible, isolation valves in raw water piping and appurtenances should be stainless-steel ball valves. The scraping action of the ball valve performs well in the presence of zebra mussel shells. Butterfly valves should be avoided where possible as they do not seal well with mussel shells in the piping system, which can result in leakage.

j. Powerhouses should install bioboxes to monitor for zebra mussel presence within the powerhouse raw water systems. Bioboxes use a small amount of raw water (3–5 gpm [11.3-18.9 lpm]) from the powerhouse raw water system and run it over a series of coalescing plates. This creates an ideal habitat for zebra mussel growth. Bioboxes allow project staff to monitor for zebra mussels within their raw water system without constant disassembly of strainers or coolers.

k. Where possible, indication equipment such as flow meters and level transmitters should be replaced with non-contact type equipment.

l. The HDC has evaluated several commercially available and experimental methods for zebra mussel abatement in hydroelectric powerhouses. There is no single recommendation to treat for zebra mussels, as each powerhouse raw water system requirements are unique. However, success has been demonstrated at USACE hydroelectric facilities with UV and copper ion-based molluscicides to prevent settlement of zebra mussels in raw water piping systems and to remove already settled colonies.

m. To determine dosing regimes for zebra mussel abatement systems, historical water quality data is critical. Zebra mussels produce larvae and spread only when water temperatures are above 50 °F (10 °C). Therefore, abatement systems are needed only for the months when reservoir temperatures are above this threshold. Furthermore, dosage rates for copper-based molluscicides and UV are based on specific water quality parameters such as dissolved solids, dissolved oxygen, and turbidity. An abatement system should be procured only when the necessary water quality data has been obtained. Failing to do so may result in an undersized or oversized system.

24–4. Generator and Turbine Cooling Water System

a. General. The generator and turbine cooling water system provides cooling water for generator air coolers, generator and turbine bearing oil coolers, and when of suitable quality, the turbine glands and wearing rings. The overall system is a joint design effort involving the water supply, discharge, and external equipment determined by the powerhouse designers, as well as the unit requirements and equipment determined by the generator and turbine manufacturers. Close coordination between the design responsibilities is required.

b. Flow Rate Requirements.

(1) The cooling water requirements for the plant were determined by the original generator and turbine suppliers and depended, in part, on the temperatures (or assumed temperatures) of the available water supply source. Flow requirements are usually large, in the 400–1,600 gpm (1514 lpm – 6057 lpm) range per unit, for typical units.

(2) Gland and wearing ring flow requirements are determined by the turbine supplier. Turbine contracts require the supplier to furnish these figures, and turbine guarantees depend, in part, on the stated flows being provided. There is historically little correlation between unit size and shaft size or speed with required flows. However, they can total a significant demand as stated requirements have been up to 35 gpm (132.5 lpm) or more per unit.

(3) Increasing cooling water flow rates is typically very difficult and cost prohibitive due to the difficulty of enlarging intakes and embedded piping. When considering unit uprates, it is a conservative assumption to assume the cooling water flow rate cannot be changed.

(4) Cooling water flow rates of existing installations should be verified using independent instruments prior to using values in any sizing calculations. Historical calculations and test reports often use rough numbers and do not always represent current conditions. Permanently installed flow meters are often out of calibration.

c. Temperature.

(1) The water supply temperatures must be verified by all available sources and consider the seasonal extremes in climate conditions for the project site. Original plant designs may have made conservative assumptions about what water temperatures

would be. Water temperatures may have changed since the project was originally built due to external environmental conditions or operational changes at the project. Plant logs, data from river monitoring sites, and other data sources should be reviewed for recent historical water temperatures.

(2) Some plants are equipped with intake structures that are capable of pulling water from multiple elevations in an effort to control downstream river temperatures. The mix of water used impacts the cooling water temperature and needs to be accounted for cooling capacity.

(3) For rehabilitation work involving raw water outfalls from the plant, consider the possibility that monitoring the temperature and flowrate might be needed in the future to measure the quantity of heat added to the river.

d. *Sources*.

(1) *Spiral Case*.

(a) For units with operational heads up to about 250 ft (76.2 m), the preferred source of cooling water is a gravity supply from an inlet in the spiral case or spiral case extension.

(b) In multi-unit plants, an inlet is provided for each unit with a crossover header connecting all units to provide a backup water supply to any one unit. Crossovers between pairs of units only are not considered adequate since there is no emergency source from an unwatered unit.

(c) The spiral case source is usually satisfactory for unit bearing coolers and generator bearing coolers, and can be adequate for gland and wearing ring use with proper filtering and adequate head.

(d) Screening requirements of water intakes placed in the spiral case were minimal during the time of original dam construction, as the penstock or turbine intake trash racks prevented large debris from entering the water passageway. In some river basins, there are concerns that migrating fish can inadvertently enter the water supply intakes due to a too-large of screen opening. As such, there are efforts to modify intake screens to have smaller openings. Finer screens can increase head losses through the cooling water system and the impacts of such screens need to be considered on the supplied systems.

(2) *Tailwater*.

(a) For higher head projects above 250 ft (76.2 m), the usual source of cooling water is a pumped supply from tailwater. This normally provides the same quality as the spiral case gravity system.

(b) Pump redundancy is required. Redundancy can be achieved by using two pumps per unit. Alternatively, redundancy can also be achieved by using a single pump per unit and connecting all units with a common header. One or more backup pumps are connected to the common header to provide supply for a pump out of service. Other arrangements to provide backup pump capacity may also be acceptable.

(c) Pump intakes should be located such that the intakes remain flooded at minimum tailwater.

(d) Continuously rising pump performance curves are required,

(e) Pumps are typically centrifugal type, but pump type and size should be selected based off of the required pump output.

(f) Pumps should be driven by electric motors with a synchronous speed that does not exceed 1,800 rpm.

(3) *Other Sources*.

(a) It is unlikely that other suitable sources will be available or needed for cooling requirements, but alternate sources should be considered for gland requirements. Silt or other abrasive material is usually present in varying degrees in reservoir water, at least seasonally, and since abrasive material is injurious to glands, an alternate source or additional treatment is usually required.

(b) The potable water system is normally the best alternate if the supply is adequate or could be economically increased. This is usually in the case of a well supply requiring little chlorination.

(c) Where potable water is used, cross connections from the cooling water source with backflow protection should be provided for emergency use.

e. Head Requirements.

(1) Normally, the cooling water supply should provide a minimum of 10 psi (68.9 kPa) differential across the connection to the individual cooler headers.

(2) Available gravity head, cost of a pumped supply, and cost of coolers all enter into an optimum cooler differential requirement and require early design consideration to assure a reasonable figure for the generator and turbine specification.

(3) Gland and wearing ring differential head requirements should be obtained from the turbine supplier.

f. Water Purity and Treatment.

(1) Cooling water purity requirements are moderate, permitting non-potable supplies with limited silt in suspension. Gland and wearing ring purity requirements are nominal requiring only the removal of abrasive material.

(2) Water for coolers, glands, and wearing rings normally require only straining or filtration. Typical strainer requirements for coolers permit 3-mm (1/8-in.) perforations, but strainer specifications for existing projects should be obtained as a guide to complete design requirements. Unnecessarily fine strainers requiring more frequent servicing should be avoided.

(3) Strainers should be duplex type to allow filter cleaning while maintaining continuous water flow. Automatic or manual duplexing is acceptable. Simplex type strainers are acceptable if alternate water sources can be used to maintain continuous flow. At a minimum, strainers should have local indication of a full strainer basket, but remote indication to a central annunciation or alarm panel is preferable.

(4) Filters are required for gland water unless the supply is the potable water system. The system should provide continuous operation when an individual filter requires cleaning.

g. Piping.

(1) All piping should be consistent with Chapter 22.

(2) Water takeoffs from the spiral case or the spiral case extension should be within 30 degrees of horizontal center line to minimize debris and air.

(3) A removable 3-ft section of straight pipe should be provided in the generator bearing supply line for temporary installation of a flow meter.

h. Valving.

(1) A shutoff isolation valve should be located as close to the water takeoff as practicable for emergency shutoff.

(2) Isolation valves should be installed on the inlet and outlet of each heat exchanger to allow isolation and/or removal of an individual heat exchanger. Full-port ball valves are the preferred type of valve for isolation and shut-off valves.

(3) Throttling or balancing valves should be provided to regulate the water flow to each heat exchanger. Manually operated globe-type valves are often sufficient, especially for plants that see minimal seasonal variations in cooling water temperature. For plants that see more variations, throttling valves controlled by electric or pneumatic actuators can be provided. Valves should regulate using feedback from the bearing or oil temperature.

(4) Throttling valves should be placed on the outlets of heat exchangers rather than the inlets to maintain high water pressure in the heat exchanger. The pressure drop across a throttling valve can reduce the water pressure in the heat exchanger such that the water pressure is less than the static oil pressure in the bearing tub. In this situation, a leak in the heat exchanger results in the higher pressure oil flowing into the lower pressure water that is undesirable.

i. *Instrumentation*.

(1) *Flow Meters*.

(a) At a minimum, each unit cooling water supply line should be provided with a flow meter. Separate flow meters for the generator coolers and bearing coolers are not required, often provided based on project requests and requirements. Flow meters to individual heat exchangers result in excessive equipment and the additional monitoring points are not needed for regular project operations. A separate flow meter should be provided for the gland water.

(b) Local indication of the flow rate is typically sufficient. Remote indication of the exact flow rate is typically not needed as the flow rate is not being constantly modulated. Remote status of flow (on or off) should be provided by a separate flow switch.

(c) Differential pressure-type flow meters are most commonly installed as they are robust, reliable, and easily serviced and calibrated. Ultrasonic flow meters can be used, but should be of the permanent installation type and not external clamp-on. High precision is not typically needed as the flow is not regulated precisely.

(2) *Thermometers*.

(a) Thermometers on the cooling water supply are not typically required for regular project operations. Flow rates through the coolers are typically regulated based on the feedback from bearing or generator air outlet temperatures, rather than changed with water temperature.

(b) Thermometers can be provided as additional informational data points as needed or requested by the project.

(c) Cooling water discharged back to the river is considered a permitted discharge for projects covered by the National Pollutant Discharge Elimination System. For covered projects, more accurate discharge temperatures may be needed, and additional thermometers should be installed.

j. *Schematic*. A schematic of a typical generator and turbine cooling water system that uses a gravity feed can be found at the end of this chapter in Figure 24–1. A schematic of a typical generator and turbine cooling water system that utilizes a pumped feed can be found at the end of this chapter in Figure 24–2.

24–5. Transformer Cooling Water

a. Most plants now use air-cooled transformers, so there is very limited application of transformer cooling water systems. The general principles noted for the generator and turbine cooling water system are applicable for transformer cooling water except where transformers are located on the intake deck of a dam powerhouse structure. There, the pumped supply is normally from pool water rather than tailwater.

b. For the safety of the transformers, the water pressure in heat exchangers should be less than the oil pressure to prevent water from entering the transformer oil under minor seepage conditions. While this helps protect the transformers, it creates a significant concern of discharging oil to the river.

c. Transformer cooling water systems must be protected from freezing where freezing can occur.

24–6. Fire Protection Water

a. The requirement for fire protection water is normally limited to deluge systems for main power transformers but may also include fine water mist systems, hydrants, and automatic sprinklers. Refer to Chapter 21 for discussion of water-based fire protection systems.

b. The fire protection system water supply is normally from the pool and should be a gravity supply if practicable. A pumped tailwater source is an acceptable alternate. If required, a fire pump should be provided per UFC 3-600-01.

c. Two independent water supplies are required from separate water intakes. Each water supply must be sized for the total peak system demand. Water supplies may be cojoined but must be separable by valving arrangements. In some cases, water is sourced from the water passages of units, in which case a redundant water source might be required in case those units are unwatered.

d. Systems requiring stored water must not use the potable water storage tank(s) and must be provided with dedicated storage tank(s).

24–7. Potable Water System

a. *General*.

(1) The primary demand on the potable water system is drinking and sanitation water for the powerhouse. In addition, the potable water system is often used as the main source for gland and wearing ring water and, in some projects, supplies other potable water requirements external to the powerhouse.

(2) The requirements for the potable water system and design of the system are governed by the following documents. The considerations in this manual are additional USACE powerhouse-specific considerations:

(a) EM 1110-2-503.

(b) UFC 3-230-01 (superseded TM 5-813-1 and TM 5-813-4).

(c) UFC 3-230-03 (superseded TM 5-813-3).

(d) UFC 3-420-01 (superseded TM 5-810-5).

b. *Water Requirements*.

(1) The powerhouse drinking and sanitation flow demand, including provisions for visitors, should be determined according to UFC 3-420-01. This is normally on a fixture unit basis. However, in the case of large powerhouses, the main restrooms near the service bay are usually adequate for all personnel requirements, and additional facilities are provided, remote from the service bay, for convenience. These require the piping design on a fixture unit basis, but a reduction in the fixture unit basis water demand, commensurate with the intended usage, can be justified.

(2) Gland and wearing ring flow requirements are as determined under paragraph 24–4b(2).

(3) Principal quality requirements are safety in health considerations and acceptable taste qualities consistent with the area in which the project is located.

c. *Sources*.

(1) Sources for powerhouse potable water requirements include the following:

(a) Pool water.

(b) Tailwater.

(c) Powerhouse well.

(d) General project supply.

(e) Existing construction supply.

(f) Local public supply.

(2) The order of preference depends on several variables, but it is generally preferable to supply all project potable water requirements from one system, whether it be a powerhouse or non-powerhouse source. All sources should be considered, and a choice made on the basis of reliability, purity, required treatment, and cost. EM 1110-2-503 and UFC 3-230-01 provide a discussion of factors to consider in evaluating water supplies.

(3) For non-powerhouse sources, the powerhouse design responsibility is limited, but includes mutual verification of demand, supply, reliability and cost, and provisions for necessary standby sources.

(4) *Wells.*

(a) Good wells usually provide the best source of potable water in terms of purity, treatment, and temperature considerations. The existence of good wells in the vicinity, along with favorable geological indications, suggests serious consideration of a well supply. The primary well and storage reservoir should be adequate for all initial and potential expansion demands, and there should be a backup well at least adequate for system operation under conservation operation.

(b) In the evaluation of a potential well supply, other considerations should include the following: water rights; probability of increased domestic, agricultural, or commercial demand for underground water; and effects of pool raising and pool level variations.

(c) The power plant design analysis should include a record of all factors considered in the selection of a well supply.

(5) *Pool or Tailwater Supply*.

(a) Reliability is the major advantage of either a pool or tailwater source. Quality is usually questionable, and treatment plants providing coagulation, chlorination, sedimentation, and filtration may be required.

(b) It is usually desirable to combine a pool or tailwater potable supply with other non-potable, powerhouse raw water requirements as far as intakes, intake piping, and strainers are concerned.

(c) Intakes from either pool or tailwater should not be located in penstocks, unit intakes, or draft tubes in such a way that system water is not available 100 percent of the time.

(6) *Construction Source or Public Supply*. An adequate existing construction source or public source is unlikely but should be investigated in view of the obvious advantages, particularly of a substantial, state-regulated system.

(7) *General Project Supply*. A general project supply may be from one or more of the previous sources discussed and may originate under powerhouse design or non-powerhouse design. It is usually the optimum arrangement for the project as a whole. If the design is non-powerhouse, all powerhouse requirements should be determined and adequacy of the supply verified by the powerhouse design office.

d. *Pump Versus Gravity Considerations*.

(1) *High Head Projects*. Projects with over 250 ft (76.2 m) head should be provided with a pumped potable water supply with the pumps taking water from a tailrace intake. Pressure-reducing valves to use gravity heads from higher pools are not recommended unless tailwater is excessively contaminated or not always available.

(2) *Low Head Projects*. Project with under 250 ft (76.2 m) head may use gravity head to good advantage, providing pool fluctuations do not result in less than 15 psi (103 kPa) pressure at the highest fixture served. Pressure-reducing valves with downstream relief valves can be used to provide a reasonably constant pressure if necessary. Temporary failure of a pressure-reducing or relief valve will not endanger fixtures or piping up to 250 ft (76.2 m) of head. For rehabilitation work on these systems, consider ease of shut-off and system maintenance, and ensure redundancy against failures, which could lead to flooding of the powerhouse.

e. *Pump Requirements*.

(1) Pumped potable water requirements should be provided by two pumps, with either pump capable of pumping the total system peak demand.

(2) Pumps should normally be either vertical or horizontal centrifugal with constant rising characteristic curves and should be located to ensure a flooded suction under all operating conditions. Turbine-type pumps should also be considered for low flow, higher head requirements.

(3) Controls should be conventional lead-lag for a hydropneumatic tank or gravity tank, as applicable.

(4) Unless the potable water pumps are pumping from a strained raw water supply, duplex suction strainers are required.

f. *Water Treatment*.

(1) Water treatment should meet the minimum requirements in EM 1110-2-503 and UFC 3-230-03.

(2) A water quality analysis should be obtained to determine the treatment required. In event that full treatment is not initially indicated, space, piping sizes, and connections should be provided to expand treatment facilities if required by subsequent changes in water quality.

(3) Power plant uses do not require all water qualities considered desirable for domestic use, so judgment in applying treatment criteria is necessary.

g. Storage Tank.

(1) Storage and storage tanks should be consistent with UFC 3-230-01.

(2) A gravity tank or other gravity sources with capacity and head to sustain the project for a week or more under conservation operation is the most desirable storage facility. When a suitable tank location is available, and particularly where there is a substantial non-powerhouse project demand, design emphasis should give first priority to a gravity system. The design responsibility for the storage facility is usually non-powerhouse for such systems.

(3) Where a gravity system is not feasible, a hydropneumatic tank located in the powerhouse is normally provided for the powerhouse requirements. The tank should be sized so that, in combination with high-average system demand and pump delivery, it will provide a minimum 30-minute chlorine contact period and allow approximately 10 minutes between pump starts.

h. Hot Water.

(1) Hot water systems, demand calculations, and tank sizing should be provided according to UFC 3-420-01.

(2) The type, number, and location of fixtures requiring hot potable water are normally determined by architects. The piping system designer should cooperate in the planning to affect the most practical grouping of fixtures for efficiency of hot water distribution.

(3) Heaters should be the electric tank type. Where fixtures are separated by more than 60–80 ft (18.3-24.4 m) of piping, the provision of separate heaters may be more economical and should be investigated. Electrical load should be coordinated with the electrical design.

i. Piping.

(1) Refer to Chapter 22 for general piping considerations. Refer to Chapter 26 for additional piping consideration for potable water.

(2) New and repaired or rehabilitated potable water piping should be disinfected according to AWWA Standard C651.

(3) Backflow preventers are required between the potable water system and gland water piping, and also in any other interconnection between potable water piping and piping with the potential for containing non-potable water.

j. Schematic. A schematic of a typical potable water system can be found at the end of this chapter in Figure 24–3.

24–8. Raw Water System

a. Common Uses. The raw water system normally provides water for the following requirements:

(1) Air compressors and aftercoolers.

(2) Air conditioning cooling water.

(3) Historically, some systems were designed for dual use for both deck washing and fire protection. This combined arrangement does not meet national fire code requirements. Rehabilitation projects must provide either or both a separate deck

washing system and a separate fire protection system, neither of which is interconnected to the other.

(4) Pump pre-lube.

(5) Unwatering and drainage deep well.

b. Other Uses. Certain projects may use water from the raw water system for the following requirements:

(1) Gland water.

(2) Transformer deluge system.

(3) Station service transformer cooling water.

(4) Source for the potable water system.

(5) Fine water mist systems.

c. Flow Rate Requirements.

(1) Flow requirements for air compressors, aftercoolers, and pump pre-lube should be obtained from equipment suppliers and verified against existing projects with similar equipment.

(2) Air conditioning flows must be as computed for the air conditioning system.

(3) Fire protection flow requirements must be determined according to the direction given in Chapter 21.

(4) Deck washing hose valve requirements may be based on 50 gpm (189 lpm) per 1.5-in.(3.81 cm) hose, and should assume three hoses operating at one time.

d. Water Quality Requirements. Quality requirements for the raw water system are nominal, requiring straining only if water analysis indicates the need to treat to limit scale formation in cooling coils.

e. Sources. Raw water should normally be obtained from the pool or tailwater. Other reliable sources are unlikely to be economically available; however, an existing or planned adequate gravity project source could offer some advantages and should be considered.

(1) *Pool*. For projects up to about 250 ft (76.2 m) head, a gravity pool supply is usually preferable.

(2) *Tailwater*. For projects over 250 ft (76.2 m) head, or where pool head fluctuates over a wide range, a pumped tailwater supply is normally used. For high head projects in tidal locations with brackish tailwater, special materials and/or equipment are required.

(3) *Generator Cooling Water*. The generator cooling water crossover header should normally be the supply to the raw water system. Where the generator cooling water is a gravity supply that is not always available, a standby raw water supply intake and piping should be provided.

f. Head.

(1) Optimum head for raw water requirements can vary considerably depending on the particular equipment selected and its location. System design should consider the inherent flexibility in required differentials across coils and heat exchangers, as well as locations, to effect the simplest and most dependable system.

(2) The provision of booster pumps or pressure-reducing relief valve stations to provide different head in a portion of the system should be evaluated on the basis of requirement rather than desirability.

g. Treatment. Strainer perforations of 1/8 in (3.2 mm) are normally adequate for all raw water system requirements (see paragraph 24–4f for further recommendations).

h. Pumps.

(1) The pump principles noted in paragraph 24–4.d(2) are generally applicable to pumps for the raw water system.

(2) The system design should provide standby pump capacity for all pumped requirements.

(3) For pumped tailwater systems, the raw water system requirements can be included in the generator cooling water pump's capacity and supplied through the crossover header, with booster pumps provided if required.

i. Piping.

(1) Refer to Chapter 22 for general piping considerations.

(2) Piping for deck washing hose cabinets subject to freezing should be provided with automatic drainage.

(3) A 3/4-in (1.9 cm) hose valve should be provided at each turbine head cover for cleanup.

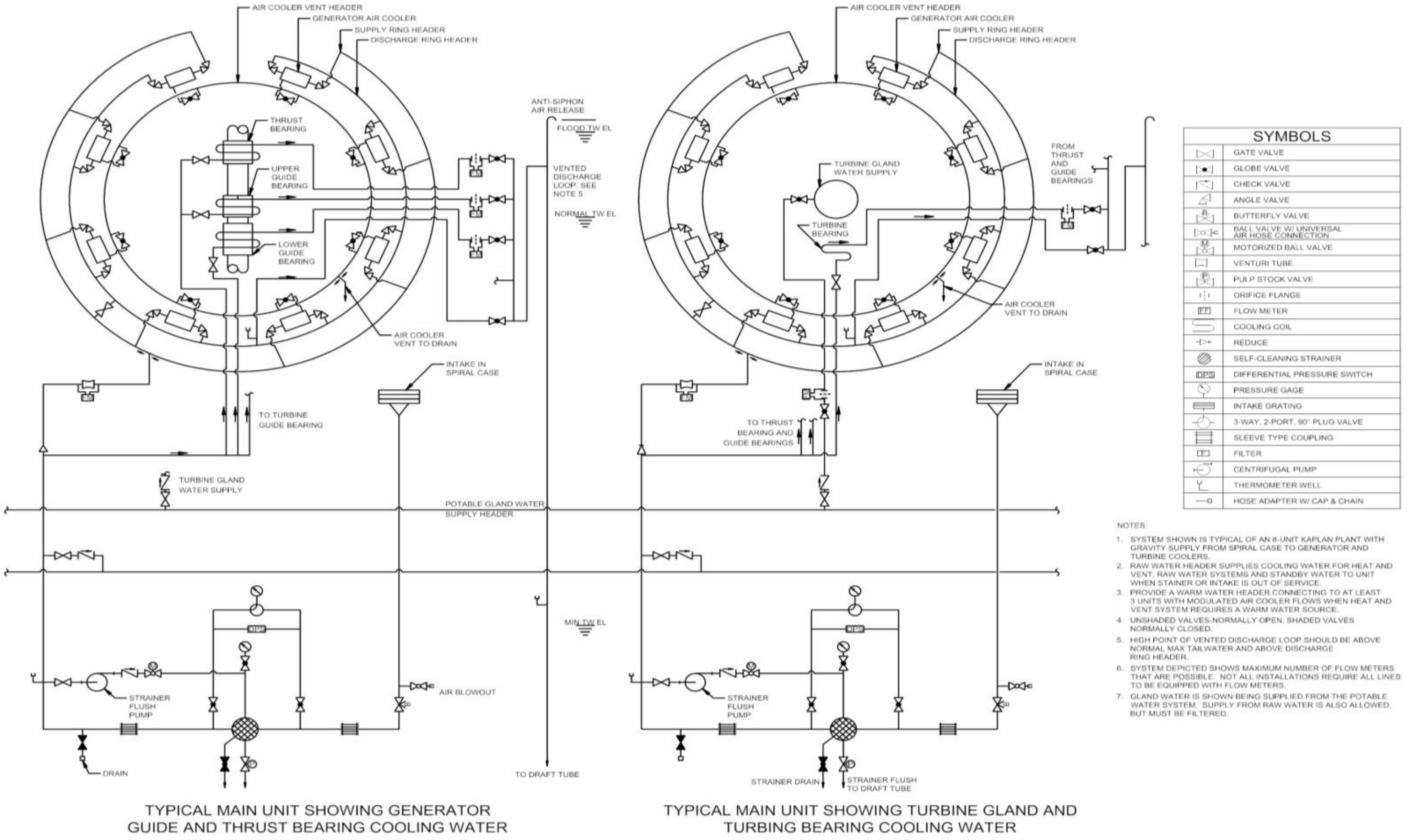
(4) A 1.5-in (3.81 cm) hose connection should be provided near turbine access hatches to wash down the turbine.

j. Deck Washing Hose Cabinets.

(1) The deck washing provisions were intended to meet the normal standards of a deck washing system.

(2) Areas used for loading or unloading from vehicles or railroad equipment, heavy maintenance areas, potential storage areas, and where there is oil piping should be accessible to simultaneous hose-nozzle coverage from two directions.

k. Schematic. A schematic of a typical raw water system from a large plant can be found at the end of this chapter in Figure 24–4. A schematic of a typical raw water system from a small plant can be found at the end of this chapter in Figure 24–5.



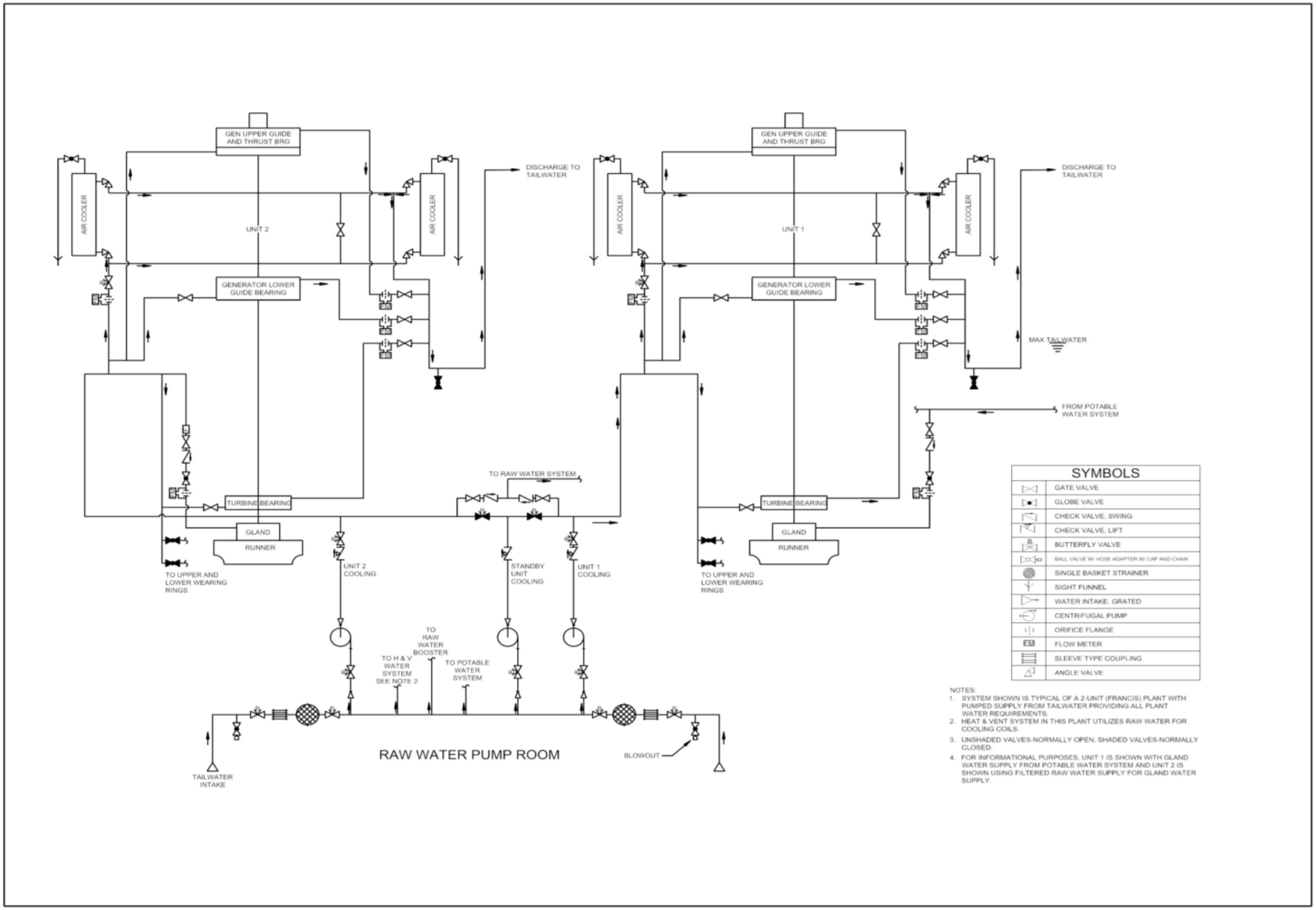
TYPICAL MAIN UNIT SHOWING GENERATOR GUIDE AND THRUST BEARING COOLING WATER

TYPICAL MAIN UNIT SHOWING TURBINE GLAND AND TURBING BEARING COOLING WATER

NOTES:

1. SYSTEM SHOWN IS TYPICAL OF AN 8-UNIT KAPLAN PLANT WITH GRAVITY SUPPLY FROM SPIRAL CASE TO GENERATOR AND TURBINE COOLERS.
2. RAW WATER HEADER SUPPLIES COOLING WATER FOR HEAT AND VENT, RAW WATER SYSTEMS AND STANDBY WATER TO UNIT WHEN STAINER OR INTAKE IS OUT OF SERVICE.
3. PROVIDE A WARM WATER HEADER CONNECTING TO AT LEAST 3 UNITS WITH MODULATED AIR COOLER FLOWS WHEN HEAT AND VENT SYSTEM REQUIRES A WARM WATER SOURCE.
4. UNSHADED VALVES-NORMALLY OPEN, SHADED VALVES NORMALLY CLOSED.
5. HIGH POINT OF VENTED DISCHARGE LOOP SHOULD BE ABOVE NORMAL MAX TAILWATER AND ABOVE DISCHARGE RING HEADER.
6. SYSTEM DEPICTED SHOWS MAXIMUM NUMBER OF FLOW METERS THAT ARE POSSIBLE. NOT ALL INSTALLATIONS REQUIRE ALL LINES TO BE EQUIPPED WITH FLOW METERS.
7. GLAND WATER IS SHOWN BEING SUPPLIED FROM THE POTABLE WATER SYSTEM. SUPPLY FROM RAW WATER IS ALSO ALLOWED, BUT MUST BE FILTERED.

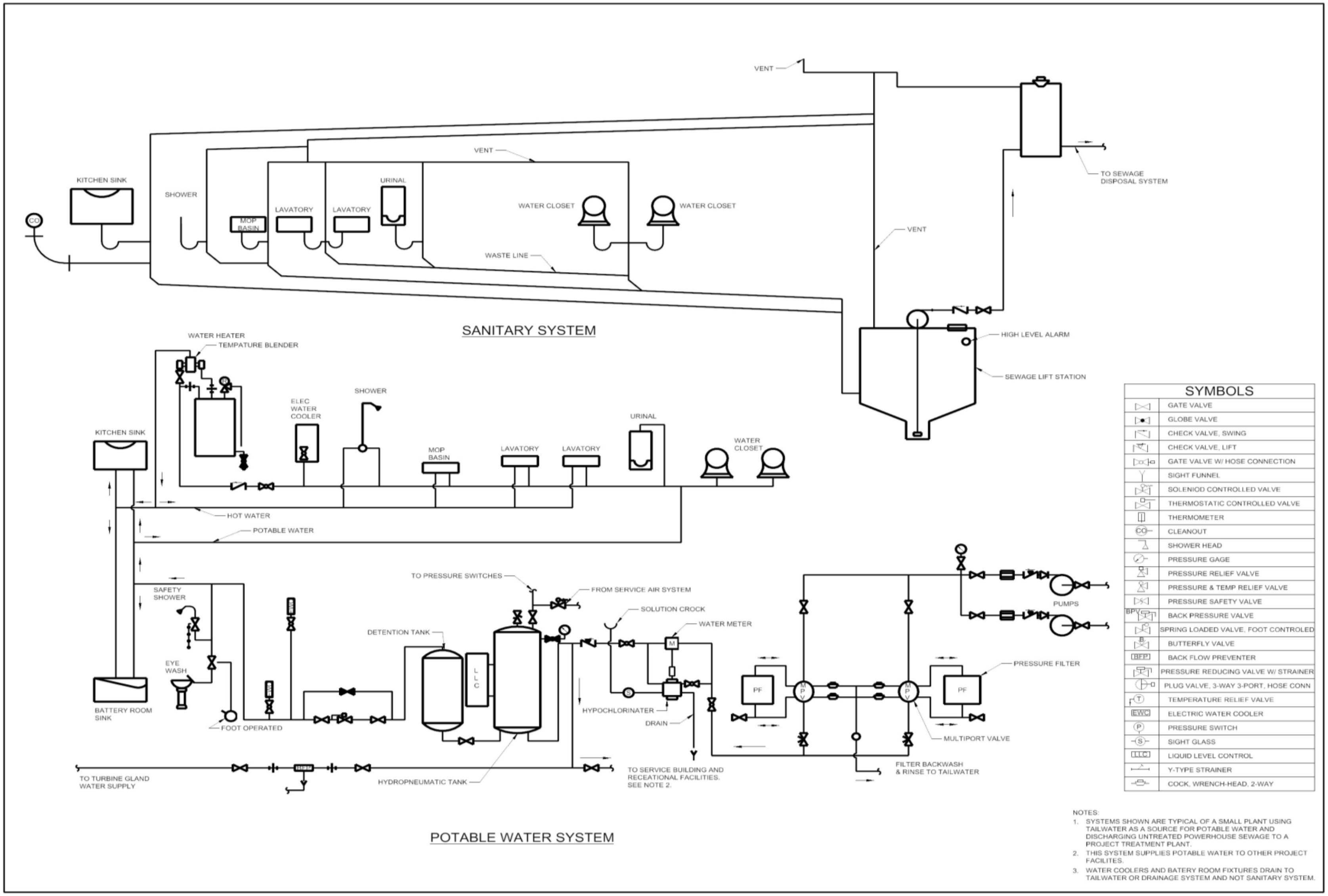
Figure 24–1. Example of a typical gravity feed cooling water system



NOTES:

1. SYSTEM SHOWN IS TYPICAL OF A 2-UNIT (FRANCIS) PLANT WITH PUMPED SUPPLY FROM TAILWATER PROVIDING ALL PLANT WATER REQUIREMENTS.
2. HEAT & VENT SYSTEM IN THIS PLANT UTILIZES RAW WATER FOR COOLING COILS.
3. UNSHADED VALVES-NORMALLY OPEN, SHADED VALVES-NORMALLY CLOSED.
4. FOR INFORMATIONAL PURPOSES, UNIT 1 IS SHOWN WITH GLAND WATER SUPPLY FROM POTABLE WATER SYSTEM AND UNIT 2 IS SHOWN USING FILTERED RAW WATER SUPPLY FOR GLAND WATER SUPPLY.

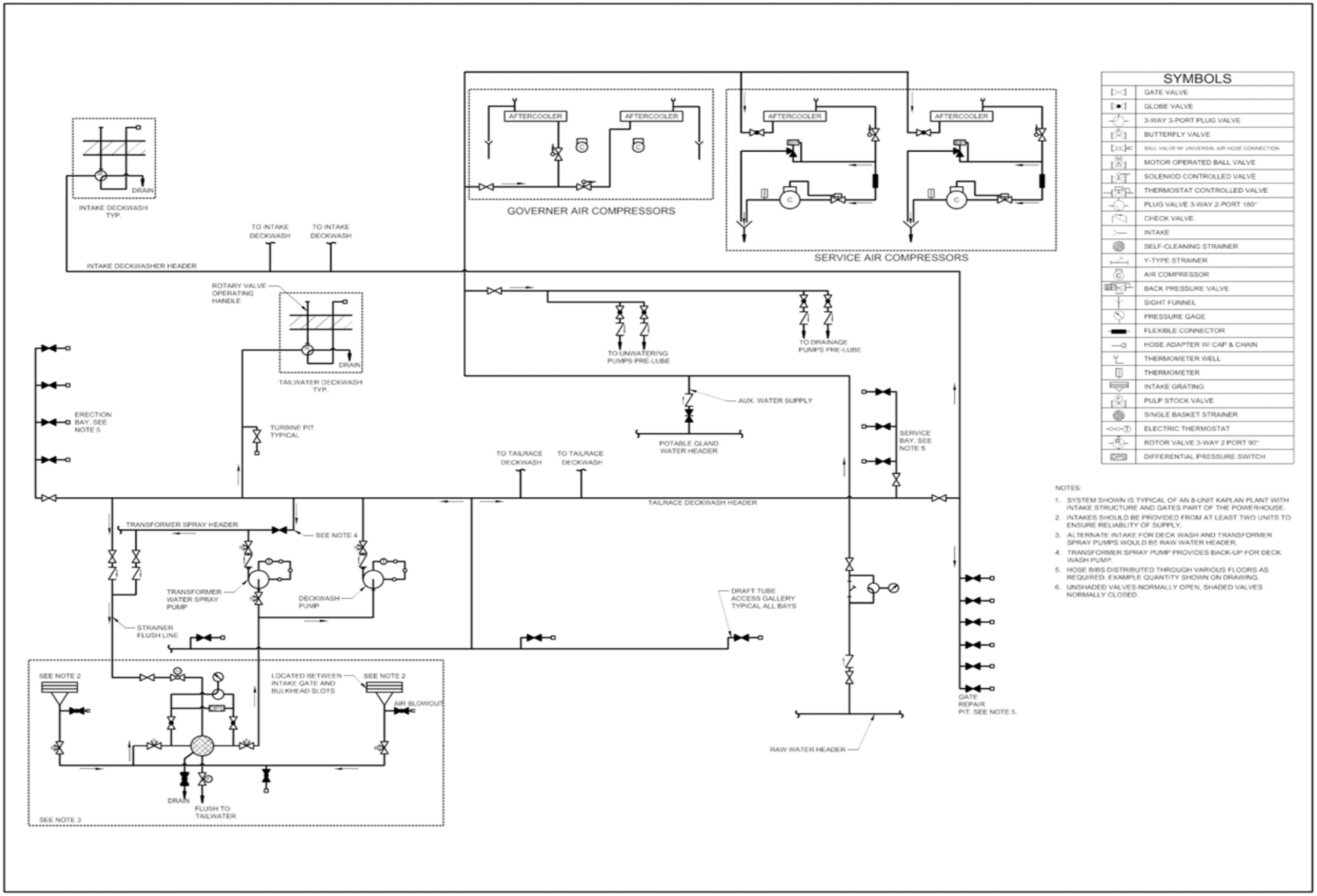
Figure 24–2. Example of a typical pressure feed cooling water system



NOTES:

1. SYSTEMS SHOWN ARE TYPICAL OF A SMALL PLANT USING TAILWATER AS A SOURCE FOR POTABLE WATER AND DISCHARGING UNTREATED POWERHOUSE SEWAGE TO A PROJECT TREATMENT PLANT.
2. THIS SYSTEM SUPPLIES POTABLE WATER TO OTHER PROJECT FACILITES.
3. WATER COOLERS AND BATERY ROOM FIXTURES DRAIN TO TAILWATER OR DRAINAGE SYSTEM AND NOT SANITARY SYSTEM.

Figure 24–3. Example of potable water and sanitary systems



NOTES:

1. SYSTEM SHOWN IS TYPICAL OF AN 8-UNIT KAPLAN PLANT WITH INTAKE STRUCTURE AND GATES PART OF THE POWERHOUSE.
2. INTAKES SHOULD BE PROVIDED FROM AT LEAST TWO UNITS TO ENSURE RELIABLITY OF SUPPLY.
3. ALTERNATE INTAKE FOR DECK WASH AND TRANSFORMER SPRAY PUMPS WOULD BE RAW WATER HEADER.
4. TRANSFORMER SPRAY PUMP PROVIDES BACK-UP FOR DECK WASH PUMP.
5. HOSE BIBS DISTRIBUTED THROUGH VARIOUS FLOORS AS REQUIRED. EXAMPLE QUANTITY SHOWN ON DRAWING.
6. UNSHADED VALVES-NORMALLY OPEN, SHADED VALVES NORMALLY CLOSED.

Figure 24–4. Example of a typical raw water system for a large plant

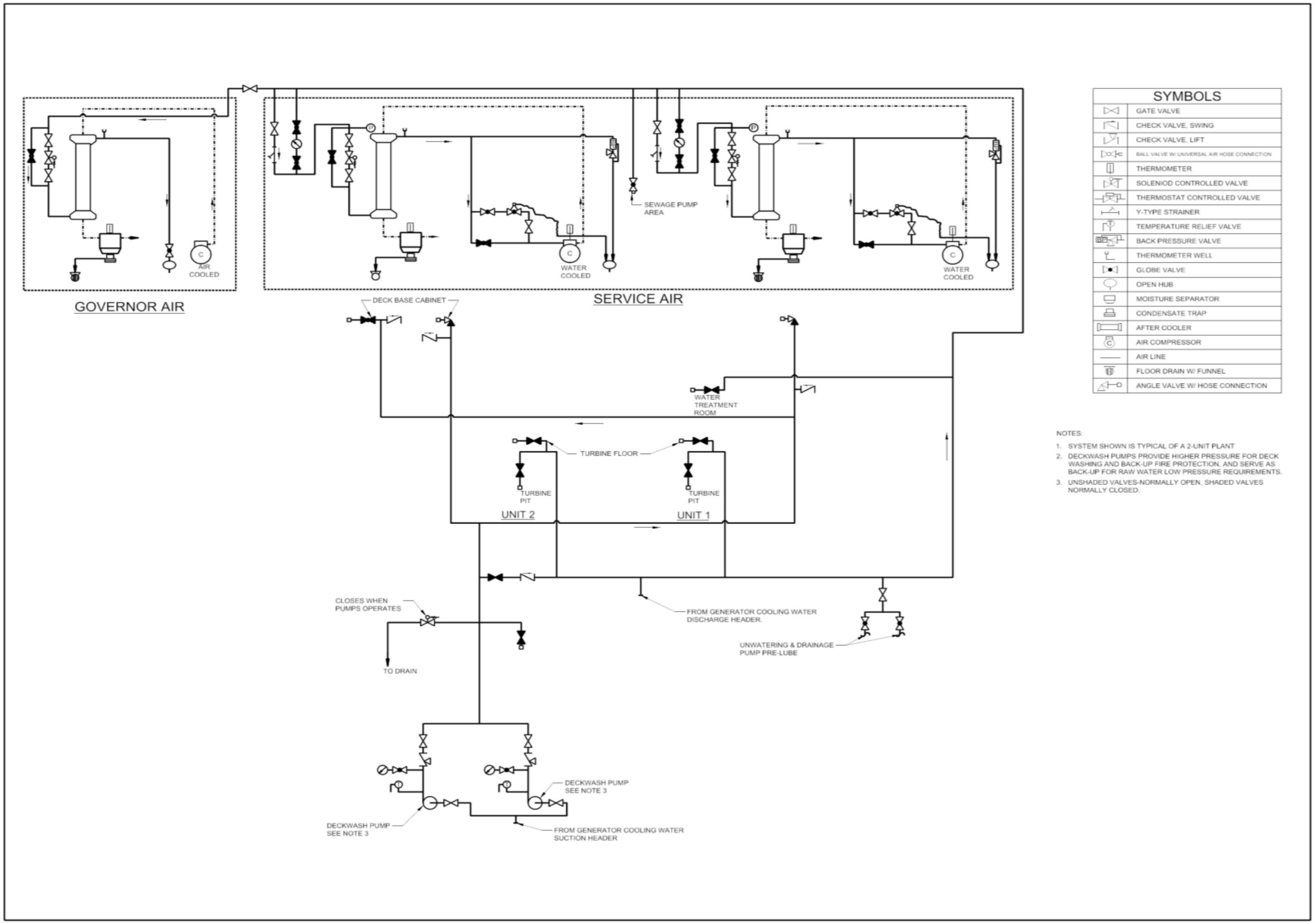


Figure 24–5. Example of a typical raw water system for a small plant

Chapter 25
Compressed Air Systems

25–1. General

a. Compressed air systems are required in powerhouses for operation and to facilitate maintenance and repair. Service air, brake air, and governor air comprise the three main systems needed in all powerhouses. Some powerhouses also require an independent draft tube water depression system. The designer should use UFC 3-420-02FA for general guidance and general information on compressed air systems. The designer should note that fiber reinforced plastic (FRP) pipe and any other thermoplastic piping is not allowed in powerhouse compressed air applications.

b. Reliability, flexibility, and safety are prime design considerations. This chapter touches on relevant requirements of OSHA and the EPA, but cannot substitute for consultation with the appropriate legal, environmental, health, and safety experts.

25–2. Service Air System

a. *General*. The service air system is a nominal 100 psi (700 kPa) system providing air for maintenance and repair, control air, hydropneumatic tank air, charging air for the brake air system, and in some cases, air for ice control bubblers or air nozzles for debris removal from water intakes.

b. *Service Air Requirement*.

(1) *Routine Maintenance*. Supply 50–80 cfm (25–40 L/s) for wrenches, grinders, hammers, winches, drills, vibrators, cleaning, unplugging intakes, lines, etc.

(2) *Major Maintenance and Repair*. Supply 300–400 cfm (140–190 L/s) for sandblasting, painting, cleaning, etc. Normally, this capacity should be provided with portable equipment. For projects too remote from a Government or commercial source of temporary portable equipment, installed capacity should be provided.

(3) *Ice Control Bubblers*. Supply 2–4 cfm per 10 ft (1–2 L/s per 3 m) width of trash rack with bubblers operating on intakes for up to four units simultaneously. In cases where an intake structure is separated from the powerhouse, an independent air system should be installed.

(4) *Operational Requirements*. Supply 15–25 cfm (7–12 L/s) with individual assumptions as follows:

(a) Brake system charging air 2–4 cfm (1–2 L/s) per unit.

(b) Hydropneumatic tank 5–10 cfm (3–5 L/s) per unit.

(c) Control bubbler 2–5 cfm (1–3 L/s) per unit.

(d) Leakage 3–5 cfm (1–3 L/s) per unit.

c. *Total Service Air*.

(1) *Calculated Basis*. The total service air requirement may be calculated based on the previously mentioned (1) to (4) individual allowances. The figures noted are representative estimates from several existing projects and should be modified as appropriate for each project with due regard for planned O&M, equipment sizes, number of units, service factors, and information from existing similar projects.

(2) *Standard Provision Basis*. The calculated basis usually requires several arbitrary assumptions and service factors to arrive at a total service air requirement. In

lieu of the calculated basis, the following standard provisions may be used as the basis of total air requirement:

(a) 1–2-unit plants 75 cfm (40 L/s).

(b) 3–4-unit plants 100 cfm (50 L/s).

(c) Over 4-unit plants 125 cfm (60 L/s).

(3) In addition, provide 375 cfm (175 L/s) for major maintenance and repair. If this is supplied with portable equipment, add calculated ice control bubbler requirement to the above standard provisions. If the 375 cfm (175 L/s) is to be installed, assume that ice control and major maintenance are non-simultaneous requirements, such that the 375 cfm (175 L/s) will cover the ice control bubbler requirements. If the ice control bubbler is intended to run continuously for multiple days, then size the system for the 375 cfm (175 L/s) plus the calculated bubbler demand.

(4) Additional calculations for air demand must be performed when service air is connected to draft tube water depression system.

(5) *Service Air Pressure*. A nominal 100 psi (700 kPa) pressure with system variations from 85–110 psi (580–760 kPa) is satisfactory.

d. Compressors.

(1) Compressors should be heavy duty, cooled rotary screw type rated for continuous duty at low pressure applications (less than 140 psi [965 kPa]). Both dry type (non-lubricated) and lubricated rotary screw compressors are recommended and should be reviewed for cost/benefit considerations.

(2) Compressors should be heavy duty, cooled reciprocating 2-stage type rated for continuous duty at pressure applications exceeding 140 psi (965 kPa) and less than 200 psi (1400 kPa).

(3) Compressors should be heavy duty, cooled reciprocating multi-stage type with unloading feature for pressure applications above 200 psi (1400 kPa).

(4) Dry-type compressors use specialized materials for the air compressing components, but still require lubrication for other components that do not contact compressed air. These dry-type compressors may be specified when compressed air services breathing for personnel, to ensure the air is oil-free. Installing dry-type compressors does not eliminate the need to install full air filtration requirements needed to comply with OSHA 29 CFR 1910.134 for breathable air applications. Installing dry-type compressors also does not eliminate the need to install oil/water separators on the condensate discharge line, because an oil seal failure could still result in oil contamination.

(5) Cooling provisions may be air-to-water, air-to-air, or air-to-glycol heat exchangers, depending on the site constraints.

(6) Normally, aside from major maintenance, service air should be supplied by two identical compressors, each of which can supply approximately 75 percent of the requirement.

(7) Where ice control bubbler demand exceeds 25 cfm (12 L/s) and there is no installed major maintenance compressor, it is preferable to supply the bubbler demand from a separate compressor(s). Installed major maintenance and repair capacity should be provided with a single compressor when commonly available in industry, and may also be multiple compressors when portability dictates.

e. Receivers.

(1) Each air receiver should be designed, constructed, and tested according to requirements of the ASME BPVC.

(2) Receiver capacity should provide a minimum 5-minute running time with no air being used from the system for the largest connected compressor on automatic start-stop control. One or more receivers may be used for the system.

(3) Galvanized receivers are preferred, and sizes should be checked against galvanizing plant capabilities. Alternately, receivers made of carbon steel must be painted with coatings appropriate for this application both externally and internally to protect against corrosion.

(4) The receiver must be equipped with a pressure relief valve, at inlet or other port, and an automatic or timed drain valve (water trap) with corrosion-resistant muffler should be installed at the bottom to emit moisture.

(5) Piping from the compressor to the receiver should include an oil/water separator sized for the compressor flow rating.

f. Controls.

(1) The two service air compressors should each be provided with selective manual or automatic control. They should have pressure switch lead-lag control, automatic selection, and conventional load/unload operation for manual selection. A major maintenance compressor or a separate ice control bubbler compressor should be on manual control with conventional load/unload provisions. Systems requiring multiple compressors may be controlled with automated load sharing logic that is interconnected between each of the compressors, and these require periodic changes to lead-lag settings.

(2) System coolant media should be controlled to flow only when the compressor motor is energized. Automatic shutdown should be provided at minimum for low oil pressure, low oil level, high-lube oil temperature, and high-discharge air temperature.

g. System Details.

(1) *Control Air*. Control air is provided for bubbler-type controls and gauges. The flow is minor but is a continuous system load. A 100 psi (700 kPa) air supply is satisfactory, but instruments and gauges operate at lower pressures, and reducing valves are normally included with the control equipment. Pneumatic air conditioning control and operators are sometimes supplied from the service air systems. However, package air supply units supplied with the air conditioning equipment are preferred to avoid possible contamination problems.

(2) *Hydropneumatic Tank*. Refer to Chapter 24 for hydropneumatic tank requirements.

(3) Ice Control Bubblers.

(a) General.

1. An ice control bubbler system is ordinarily supplied from the power plant at projects where the powerhouse structure forms a portion of the dam and includes the intake provisions. A bubbler system is usually provided where severe freezing conditions over an extended period of time could result in heavy ice accumulation at the reservoir surface and cause damage to the trash racks and other intake systems.

Where freezing weather is probable, but bubbler installation is postponed until icing conditions are determined, minimum required embedded piping should be installed.

2. The principle on which the bubbler system operates is the raising of warmer subsurface water to prevent surface freezing. Nozzles operate effectively with a minimum submergence of 10 ft (3.0 m) and are effective to a submergence of 25 ft (7.6 m), permitting a single-level installation of nozzles to function satisfactorily over a 15 ft (4.6 m) range of reservoir water level. Each nozzle provides an approximate 12 ft (3.6 m) diameter ice-free area above the nozzle.

3. Refer to EM 1110-2-2610 for additional guidance to consider for ice control bubbler systems.

(b) *Design*.

1. Nozzle orifice should be 1/8 in. (3.2 mm) in diameter and 3/8 in. (10 mm) in length. Nozzles should discharge down. The maximum distance between nozzles should be 10 ft (3 m). Nozzles should be located close to trash rack bars and clear of trash raking equipment.

2. A control method at each takeoff from the service air header is required to match the differential across the orifice as closely as practicable to that required for the submergence. Excessive differential can result in nozzle freezing from air expansion.

3. Provide the system with an air dryer to minimize potential freezing in pipe and at nozzle. The air dryer may be bypassed during summer operations if continuous air flow is required to keep foreign matter out of pipe and nozzle system.

(c) *Piping*. The bubblers for each main unit should be on a separate branch from the service air header with an isolating valve, throttle valve, or pressure regulator, pressure gauge, and vacuum release for automatic draining of air lines to nozzles. Piping should be pitched to assure drainage through nozzles when bubblers are off and there is a drop in pool level. Embedded piping should be plugged prior to pouring to prevent the entry of foreign material.

(4) *Water Intake and Line Clearing*. Water intakes, suction lines, and drains subject to plugging with debris or silt should be provided with service air connections (blowouts) to assist in unplugging. A manual valve should be located near the blowout connection.

(5) *Air Intake Filter*. Specify the required filtration at the air intake that is appropriate for the air compressor(s) type and size selected. Selection of filter medium and particulate size rating should also consider the local ambient and environmental conditions.

(6) *Air Dryer*.

(a) Install for moisture removal to improve air quality, reduce internal corrosion of steel pipe, prolong tool life, and to also protect ice control bubbler piping from potentially freezing shut internally in extremely cold climates. Other special applications may demand additional air quality features.

(b) Provide the air dryer after the receiver tank and size it to remove moisture down to dew points below local winter extreme temperatures. The desiccant air dryers with reverse flow purging are rated for lowest dew point capabilities, but other technologies may suffice depending on the application. Coalescing and centrifugal filter technologies can be applied for higher level filtration of air delivery.

(c) For additional guidance, refer to UFC 3-420-02FA. Special applications for breathable air in pressurized respirators may have additional filtration and purification requirements that need to be in compliance with OSHA 29 CFR 1910.134.

(7) *Heat Exchanger*. Specify intercoolers and aftercoolers to be constructed of stainless-steel material for water applications to avoid rapid corrosion that is common to several river systems and is recommended for glycol applications. If a glycol system is chosen, it will likely need to be supplied by a third party or sub-contractor. For environmental reasons, the coolant media for a glycol system must be propylene glycol, not ethylene glycol.

(8) *Hose Connections*.

(a) Hose connections should be provided throughout the plant in galleries, on decks, in the generator-turbine room, in turbine pits, in generator housings, and in the maintenance shop. Generally, it should be possible to reach any area where maintenance air may be required without exceeding 100 ft (30 m) of hose. In the maintenance shop, hose connections should be located at each bench and machine tool.

(b) A hose connection with check valve should be provided at each governor tank for pre-charging the tank to service air pressure. The procedures of a hazardous energy control program (HECP) should also be implemented to prevent backflow from high-pressure side into service air side.

(c) Hose connections using quick-disconnect couplings should be installed with an isolation valve nearby and upstream in case replacement is needed and to provide shut-off in case the hose fails. The isolation valve may include the bleed-off feature when appropriate for removing stored energy from downstream side of valve or as needed to facilitate the HECP procedures.

(9) *Hose Connection Lashing*. All hose connections must be equipped with safety lashing per multiple paragraphs in EM 385-1-1. More details can be found in sections regarding Hand and Power Tools and Pressurized Equipment and Systems. This includes quick disconnects and half-turn couplings. The terms tether and lashing refer to the same secondary method of securing the hose.

(10) *Brake Air*. The brake air system is one or more separate storage and distribution systems supplied from the service air system and is covered under paragraph 25–3. Piped connections to the brake air systems should be made from the service air headers. Additional brake air description can be found in the Chapter 7.

(11) *Breathable Air*.

(a) If the system air is used in special applications for breathable air in pressurized respirators, then additional filtration and purification requirements need to be in compliance with OSHA 29 CFR 1910.134 to provide oil-free and moisture-free air. Such quality may require repeating features such as separators, air dryers, and filters to attain improvements.

(b) Breathable air may be provided by a separate dedicated system and be portable. Special filtration equipment may be installed directly prior to the end user. In all cases, air delivery should be monitored for quality.

(12) *Portable Compressor Connections*. For powerhouses where the major maintenance and repair air is to be supplied with portable compressors, deck hose connections should be provided at intervals along the decks connecting to the main

headers. The location of connections should permit convenient compressor location and reasonably short runs to the location of expected major maintenance or repairs. Headers should be sized accordingly.

h. *Drawing and Material Schedule*. Figure 25–1 shows a typical compressed air system schematic, and Table 22–1 presents piping materials and schedule.

25–3. Brake Air System

a. *General*. The brake air system comprises one or more semi-independent storage and distribution installations for providing a reliable supply of air to actuate the generator braking systems. Air is supplied at a nominal 100 psi (700 kPa) from the service air system, stored in receivers, and distributed through the governor actuator cabinets to the generator brake systems.

b. *Air Requirement*. Air volume storage is required in the system to stop all generator-turbine units simultaneously without adding air to the system and without reducing system pressure below 75 psi (520 kPa). Each unit may be assumed to require 1.5 ft^3 at 75 psi (42.5 L at 520 kPa). When this figure is being verified from generator manufacturers' data, the storage capacity computations should consider the number of brake applications per stop, the maximum brake cylinder displacement with worn linings, and the volume of all piping downstream from the control valve.

c. *Piping Receivers*.

(1) Each subsystem includes a receiver, piping from the service air system to the receiver, piping from the receiver to the governor cabinets, and piping from each governor cabinet to the respective generator brake system. Normally, a separate subsystem is provided for each pair of generator units. In the case of plants planned for an ultimate odd number of units though, one of the subsystems may serve one to three units.

(2) Each receiver should be sized to supply air for the units connected thereto and should be designed, constructed, and tested according to requirements of the ASME BPVC. Receivers made of carbon steel must be galvanized or painted with coatings appropriate for the application, both externally and internally. The receiver must be equipped with a pressure relief valve and an automatic or timed drain valve with corrosion resistant muffler at the bottom to emit moisture.

(3) Each receiver should be supplied with air from the service air system through an isolating valve, strainer, dryer, and check valve to make the subsystem unaffected by a temporary loss of pressure in the service air system. A bleed-off valve or feature should be provided between the isolating valve and the check valve to permit convenient testing of check valve tightness.

(4) A pressure-reducing valve preceded by a strainer should be provided at the discharge from each receiver to limit brake air pressure to 100 psi (700 kPa).

(5) Piping should be consistent with the piping schedule, Table 22–1.

d. *Control*. Control for application of the brakes is normally included in the governor cabinets and provided by the governor supplier.

e. *Drawing*. Figure 25–1 shows a typical brake air system in a powerhouse.

25–4. Governor Air System

a. *General*.

(1) The governor air system provides the air cushion in the governor pressure tanks. When the governor system is placed in operation, the pressure tank is filled approximately one-fourth full with oil, and the tank is then pressurized to governor-operating pressure from the governor air system.

(2) Corrections to maintain the proper oil-air ratio are required at intervals during plant operation. These corrections may be performed manually or by automated controls. The governor pressure tank (accumulator) size and operating pressure is determined by the combined volumes needed for wicket gate and turbine servomotors to comply with IEEE 125.

(3) Pressures for various sizes of most units range between 300–1,000 psi (2,100–6,900 kPa). Some governor system pressures may have been supplied or retrofitted to exceed 1,000 psi (6,900 kPa).

(4) Applicable UFGS Guide Specifications may provide additional guidance for tank capacities and details.

b. *Air Requirements*.

(1) *Quantity*. Compressor delivery should be sufficient to effect complete pressurization of a governor tank with the proper oil level in 4–6 hrs. The pressurization time should include pre-pressurizing to service air system pressure by hose connection, where such procedure is warranted. If permanent piping is installed for pre-pressurizing, or as a crosstie between two systems, careful consideration must be applied for including check valves and isolation valves. In addition to equipment features, HECP procedures should be implemented to prevent backflow from high-pressure side into service air side.

(2) *System Pressure*. The operating pressure of the governor air system should be approximately 10 percent above the rated governor system pressure.

c. *Compressor*.

(1) The total air-delivery requirement should be provided by two identical compressors, each rated at not less than 50 percent of the requirement. Compressors should be heavy duty, reciprocating, multi-stage type, water- or air-cooled, and rated for continuous duty. Rotary screw compressors are inefficient at pressures higher than 140 psi (965 kPa), and are therefore not recommended for governor systems, whereas reciprocating compressors can be built with multiple stages to achieve high pressures as needed.

(2) “Package units” are preferred. Each package should include compressor, motor, base, aftercooler, controls, unloader circuit, and other accessories recommended by equipment manufacturers to provide a complete air-system supply except for the air receiver.

(3) An oil/water separator should be installed on the condensate collection discharge prior to drain.

(4) Air cooled applications require analysis of room ventilation and/or load on HVAC system, depending on the room.

d. *Receiver*.

(1) Since manual-start, automatic-unloading control is used for governor air compressors, receiver capacity is required only to assure reasonable control action. A receiver capacity that provides 3–5 minutes compressor running time to raise receiver pressure from atmospheric to system pressure is normally suitable.

(2) Receivers must be galvanized or painted with coatings appropriate for the application, both externally and internally, and be designed, constructed, and tested according to requirements of the ASME BPVC.

(3) Piping from the compressor to the receiver should include an oil/water separator sized for the compressor volume rating.

(4) The receiver must be equipped with a pressure relief valve and an automatic or timed drain valve with corrosion-resistant muffler at the bottom to emit moisture.

e. *Controls*. Each compressor should be provided with manual start-stop and automatic load-unload control.

f. *Drawing and Material Schedule*. Figure 25–1 shows typical piping in the air compressor system. Piping material should be consistent with Table 22–1.

25–5. Draft Tube Water Depression System

a. *General*.

(1) A draft tube water depression system is required in plants with submerged turbine or pump-turbine runners where planned operations include the operation of one or more main units for synchronous condenser operation, motor starting for pumping, or spinning reserve. The system function is to displace and maintain draft tube water to a level below the turbine runner permitting the runner to turn in air.

(2) Normally, the system should be independent of other powerhouse air provisions, although some plants have been designed with connections to permit using the draft tube air depression system to supply station air.

(3) System components, particularly receivers and piping, are generally of large physical size, and preliminary design should take place concurrent with first powerhouse layouts to assure space for a practical system arrangement.

(4) For discussion on these systems refer to ASME Paper Number 66-WA/FE-9.

b. *Air Requirement*.

(1) The system should supply sufficient air to displace the draft tube water clear of the turbine runner in approximately 10 seconds, and down to 3 ft (.91 m) below the bottom of the runner in approximately 60 seconds, plus additional volume to cover air losses during initial depression. Loss of volume during initial depression should be calculated at 10 percent of the required water displacement air volume with an assumed adiabatic expansion of the air in the receivers. Deviation from true adiabatic in the receivers during a 10-second depression is minor, and the additional air resulting therefrom should be neglected in the computations.

(2) Air must also be available after initial depression to maintain the water level approximately 3 ft (.91 m) below the runner. A close estimate of this air requirement is difficult since it depends primarily on air leakage through the shaft gland and water leakage through the wicket gates. For design purposes, it can be assumed that gland leakage will be controlled to a minor flow and that required makeup air due to wicket gate water leakage will approximate 2 cfm per foot (3 L/s per meter) of unit diameter at

the wicket gates. Unit operating head, type of unit, workmanship, and wear can all influence the leakage figure, and the design should include minimum provisions for doubling this assumption if required.

(3) The air requirement for initial depression must be available in receivers because of the high, brief flow requirement. Capacity for depressing more than one unit at a time or in rapid succession is seldom justified except for motor starting for pumping. Additional capacity should be provided when supported by a favorable benefit-to-cost ratio. Air requirement for maintaining depression must be based on the planned maximum number of units requiring depression within a specified period of time.

c. System Pressure.

(1) The minimum system operating pressure during initial depression should be approximately 15 psi (100 kPa) higher than the pressure required to depress the draft tube water 3 ft (.91 m) below the runner. Maximum system pressure depends on required displacement volume and receiver capacity, but a nominal 100 psi (700 kPa) system usually provides a practicable compressor-receiver-operational pressure.

(2) For large Kaplan units with deep submergence, an economic study should be made to determine possible economies from higher system storage pressure. Included should be costs of compressors, power and receivers, receiver configuration and location, and piping costs.

d. Compressors.

(1) Compressors should be heavy duty, cooled reciprocating type, or flood-lubricated and cooled rotary screw type rated for continuous duty.

(2) Cooling provisions may be air-to-water, air-to-air, or air-to-glycol heat exchangers, depending on the site constraints.

(3) The initial depression air and maintaining air usually are supplied by the same compressors. The required capacity should be based on raising receiver pressure from minimum to maximum operating pressure while supplying makeup air to maintain depressed units. To provide a minimum of standby with a compressor out of service, the required capacity should normally be provided in two identical compressors, each rated at 50–60 percent of the total required capacity.

(4) For a project requiring several large units on motoring operation at one time, the design studies should include providing the maintaining air with one or more low-pressure compressors.

e. Receivers.

(1) Receiver capacity should be provided in one or more receivers designed, constructed, and tested according to requirements of the ASME BPVC.

(2) Receivers made of carbon steel should be painted with coatings appropriate for the application, both externally and internally.

(3) Configuration and individual volumes are often determined by space available. Consequently, early preliminary planning is necessary to secure a desirable receiver location in the powerhouse. Outdoor locations may be required in the case of large units.

(4) Receivers should normally be sized for the full initial depression requirement. Additional capacity should be provided when needed.

(5) Due to cost and space problems, an air storage facility other than ASME code tanks may sometimes appear desirable. In such a case, advance discussions with designers are recommended.

f. Control. Compressor start-stop control, automatic shutdown control, and cooling system control should be as described in paragraph 25–2e for the service air compressors.

g. System Details.

(1) *Piping*. Depression system air piping tends to be appreciably larger than conventional air lines. Besides the additional air storage provided, successful air depression depends on the rapid injection of air under the head cover. Coordination is necessary to assure adequate space, especially in the congested areas around the turbines. A material schedule and a typical draft tube water depression system are included in Table 22–1 and Figure 25–2, respectively.

(2) *Valves*. Control valves for initial depression and for maintaining depression should be quick acting with remote control. An air cylinder-operated, rubber-seated, butterfly valve is usually satisfactory for control of the initial depression. Remote electrical control should actuate a four-way solenoid valve in the air cylinder operating air line. For maintaining depression, air flow should be small enough to permit use a solenoid valve in a small line bypassing the butterfly valve.

25–6. Miscellaneous Provisions

a. Compressor Room. The compressor room should be located in a noncritical noise area on a solid foundation free from vibration. The room requires adequate ventilation for temperature control and compressor intake.

b. Compressor Discharge Lines. Compressor discharge lines to aftercoolers and receivers should not be smaller than compressor outlet, and should generally not include shutoff valves.

c. Ample Space. Compressors, intercoolers, aftercoolers, and receivers should be located with ample space for disassembly, maintenance, and safety of operating personnel.

d. Piping. Piping generally should be sized to hold pressure loss from compressor to point-of-use to 10 percent.

e. Loop Headers. Loop headers offer pressure loss and reliability advantages and should be used, particularly in multi-unit powerhouses with headers required in upstream and downstream galleries.

f. Automatic Traps.

(1) Automatic traps should be provided at moisture separators, on receivers, and at low points in piping. An automatic or timed drain valve (water trap) should be installed at the bottom of receivers to emit moisture as needed or at timed intervals. Trapped water condensate may be released into a drain line or into the atmosphere, depending on site conditions and ability to contain oil particulates. Connection to drain line should include an oil/water separator.

(2) Plumbing to release into atmosphere should use a means for noise reduction. Corrosion-resistant mufflers are recommended on all pressurized discharge points and should be required on all high-pressure systems such as governor air. Mufflers rated for high pressure are difficult to attain. Alternately, installing a standard 125 psi (862 kPa)

rated muffler on a high-pressure discharge port requires installing a control orifice between the discharge port and muffler to limit flow and reduce pressure to an acceptable level through the standard muffler.

(3) Condensate discharge should comply with the EPA requirements stated in the water discharge paragraph below.

g. Compressor, Intercooler, and Aftercooler Water Discharge.

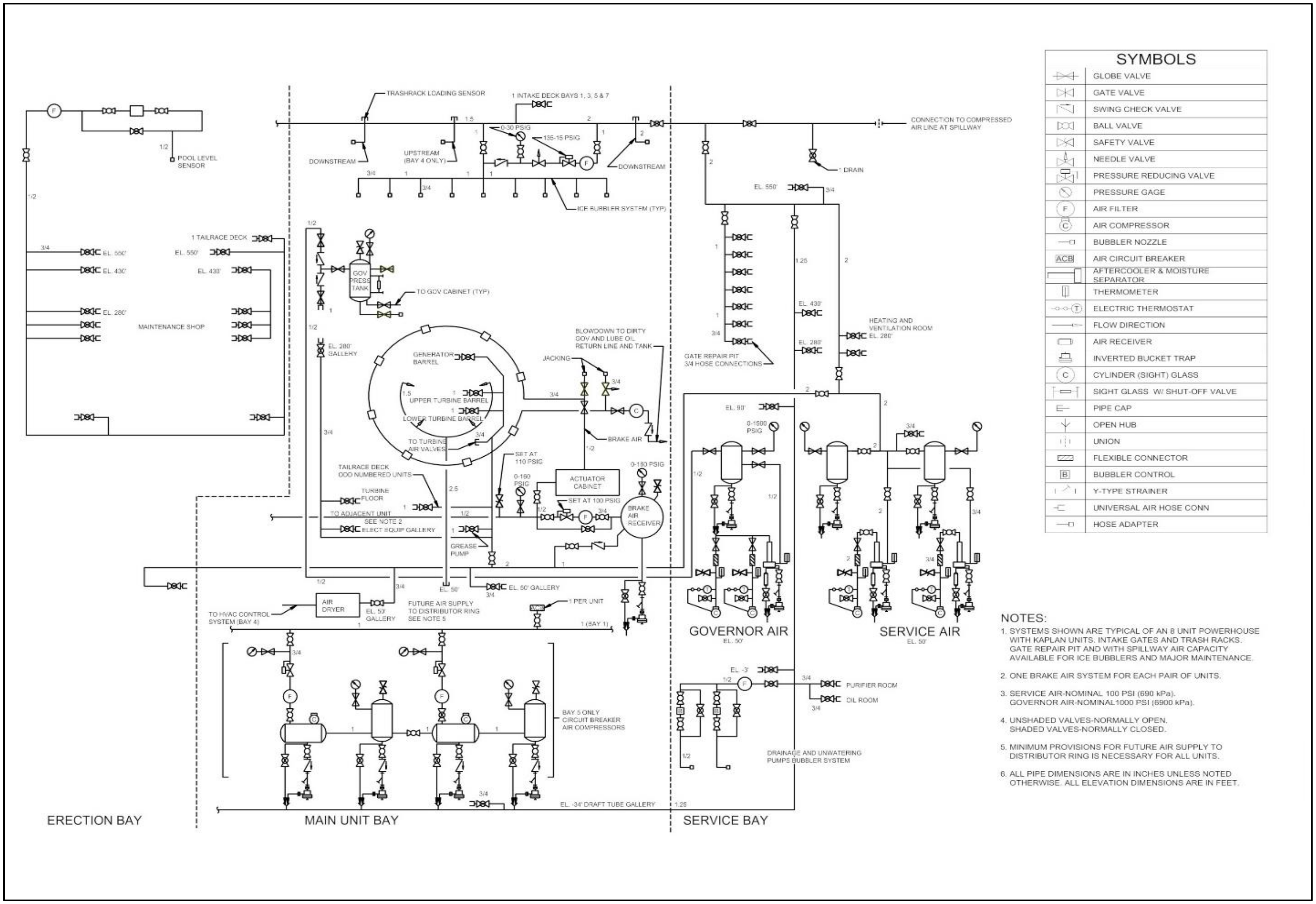
(1) The original design of compressor, intercooler, and aftercooler water discharge was typically routed through sight funnels at the point of entering a pipe drain. Environmental concerns now require the installation of an oil/water separator, either before the water condensate is plumbed to any drain pipe routed for eventual release as a discharge, or as part of the drainage system.

(2) The average compressor condensate discharge contains a quantity of oil, measured in ppm, which typically exceed EPA regulations and thus requires an oil/water separator on the discharge to comply.

(3) Requirements per the Code of Federal Regulations Title 40 CFR Part 279 state that the discharge of wastewater is subject to regulations under section 402 or section 307(b) of the Clean Water Act (also called 40 CFR Part 402 – National Pollutant Discharge Elimination System, and 40 CFR Part 307 – Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) Claims Procedures).

(4) Authority per Title 40 CFR Part 131 is assigned to state level agencies to establish water quality standards and issue certifications, and the EPA has authority to review and to approve or disapprove the state-adopted water quality standards.

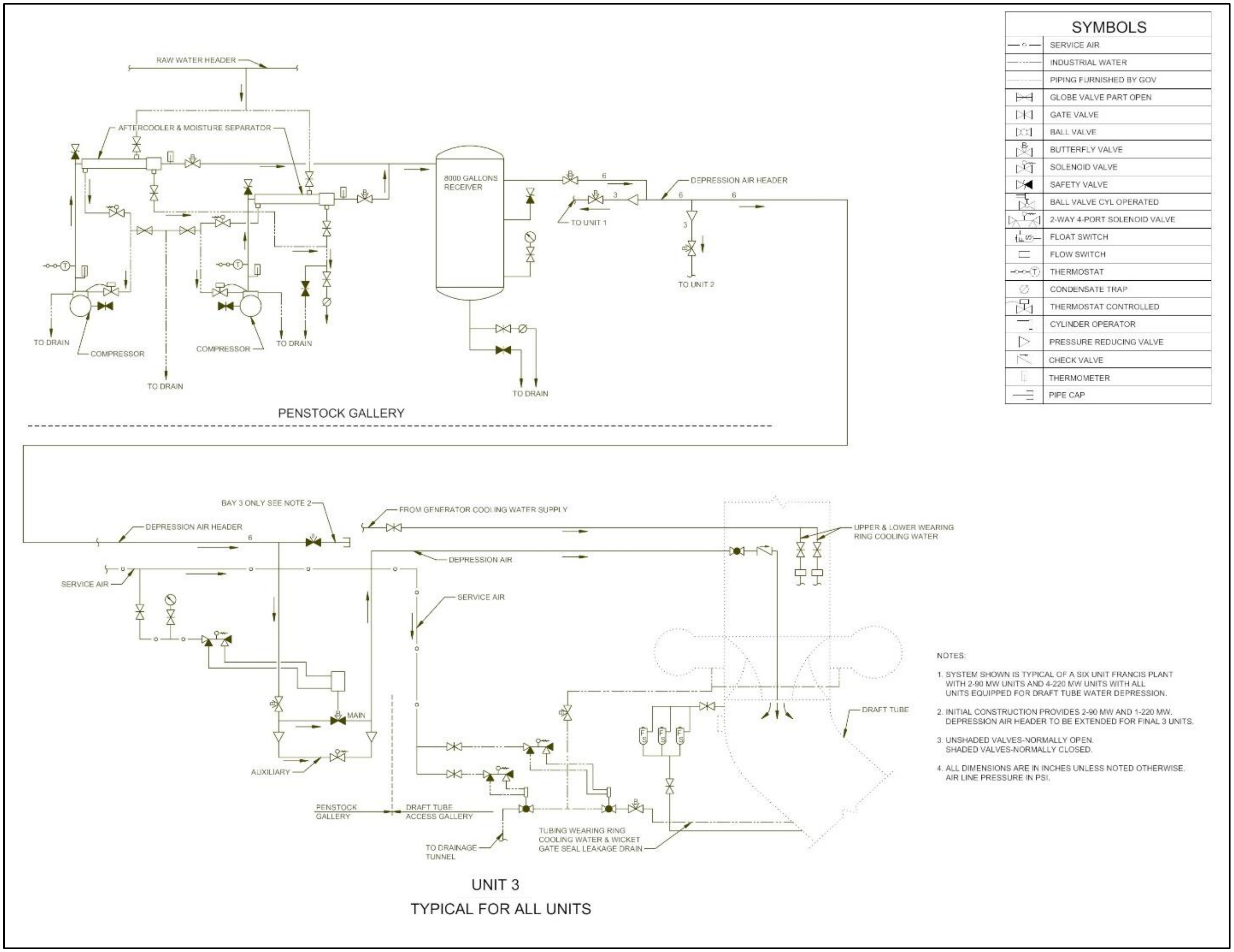
h. Headers. Headers should be sized adequately for planned plant expansion.



NOTES:

1. SYSTEMS SHOWN ARE TYPICAL OF AN 8 UNIT POWERHOUSE WITH KAPLAN UNITS. INTAKE GATES AND TRASH RACKS. GATE REPAIR PIT AND WITH SPILLWAY AIR CAPACITY AVAILABLE FOR ICE BUBBLERS AND MAJOR MAINTENANCE.
2. ONE BRAKE AIR SYSTEM FOR EACH PAIR OF UNITS.
3. SERVICE AIR-NOMINAL 100 PSI (690 kPa).
   GOVERNOR AIR-NOMINAL1000 PSI (6900 kPa).
4. UNSHADED VALVES-NORMALLY OPEN.
   SHADED VALVES-NORMALLY CLOSED.
5. MINIMUM PROVISIONS FOR FUTURE AIR SUPPLY TO DISTRIBUTOR RING IS NECESSARY FOR ALL UNITS.
6. ALL PIPE DIMENSIONS ARE IN INCHES UNLESS NOTED OTHERWISE. ALL ELEVATION DIMENSIONS ARE IN FEET.

Figure 25–1. Compressed air system schematic



NOTES:

1. SYSTEM SHOWN IS TYPICAL OF A SIX UNIT FRANCIS PLANT WITH 2-90 MW UNITS AND 4-220 MW UNITS WITH ALL UNITS EQUIPPED FOR DRAFT TUBE WATER DEPRESSION.
2. INITIAL CONSTRUCTION PROVIDES 2-90 MW AND 1-220 MW. DEPRESSION AIR HEADER TO BE EXTENDED FOR FINAL 3 UNITS.
3. UNSHADED VALVES-NORMALLY OPEN. SHADED VALVES-NORMALLY CLOSED.
4. ALL DIMENSIONS ARE IN INCHES UNLESS NOTED OTHERWISE. AIR LINE PRESSURE IN PSI.

Figure 25–2. Draft tube water depression system schematic

Chapter 26
Plumbing Systems

26–1. Preface

The requirements within this chapter are mainly applicable to the construction of new powerhouses rather than the ongoing O&M of existing powerhouses. The information is retained in this manual for reference and for any future powerhouse construction.

26–2. General

a. This chapter covers the fixtures and appurtenances for powerhouse plumbing systems, including water supply piping from in-house treatment plant; storage tank or main at building line; hot water supply; fixture drains and vents; in-house sewage treatment facility; and effluent and sludge pumps.

b. The responsibility for designing plumbing systems is not explicitly covered by ER 10-1-53, but generally, the type of work is categorized under “other powerhouse equipment and systems.” As such, work on plumbing systems is generally performed by engineers outside the HDC.

c. The powerhouse potable water supply that is used for plumbing fixtures is covered in Chapter 24. Powerhouse raw water systems are covered under Chapter 24. HDC must be consulted if changes to the plumbing system affect the water supply systems listed above, especially if turbine gland water is sourced from the potable water supply.

26–3. References

The following references, design codes, and guide specs should be considered in the design of plumbing systems for hydroelectric powerplants:

a. UFC 1-200-01.

b. UFC 3-420-01. Intended for DoD military construction work, but contains design data that can be useful in powerhouse design and should be followed where applicable.

c. UFGS 22 00 00. Intended for military and vertical construction, it has a large quantity of non-applicable material and systems, but should be used as a guide specification.

d. International Plumbing Code (IPC). Basic code for design of plumbing systems that is used and referenced by the UFCs.

26–4. Fixtures

a. Fixture type and quantity should be according to the project’s current and projected needs and all applicable codes.

b. Location, selection, and quantities of fixtures are normally architectural determinations. The mechanical design engineer should be involved early to assure practical pipe routings and space, facilities consistent with proposed water supplies and sewage treatment, and optimum grouping of fixtures.

26–5. Water Supply

a. Cold water from the potable water system (see Chapter 24) must be provided to all fixtures.

b. Hot water should be provided to all fixtures listed except water closets, urinals, drinking fountains, safety shower, and eyewash. See Chapter 24 for water heater provisions.

c. In addition to the requirements of Chapter 22, piping for plumbing systems should be sized and selected according to the following:

(1) Hot and cold water mains, branches, and risers should normally be sized for 8- to 12-fps velocity on flows obtained from fixture-unit flow demand curves. Where flow is continuous in copper lines, the velocity should not exceed 7 fps (2.1 mps) to prevent erosion of copper elbows.

(2) Continuous temperatures in the range of 140–170 °F (60–76.7 °C) for both copper and galvanized steel should be avoided.

(3) Individual fixture supply pipes should be 1/2 in (1.3 cm) except for 1 in (2.5 cm) supplies to flush valve fixtures and deluge shower-eyewash.

(4) Shutoff valves should be provided in supply lines to groups of fixtures to facilitate maintenance.

(5) See Chapter 22 for pipe material schedule.

d. Refer to Figure 24–3 for typical potable water system configuration.

26–6. Sanitary Piping

a. *Drains*.

(1) Drains from sinks, water closets, standard showers, and lavatories should be routed to the septic tank, public sewage system (if available), or other treatment facility.

(2) Drains from battery room sink and deluge shower-eyewash are normally routed to the station drainage system. Water coolers may be drained either through sanitary drains or drainage system piping.

(3) Sizing should be on fixture unit basis.

(4) Minimum slope on drains with a pipe size 3 in (7.6 cm) and smaller is 2 percent. Minimum slope on larger drains is 1 percent with 2 percent preferred.

(5) Minimum size of any drain line subject to flow of raw sewage from a water closet is 3 in (7.6 cm).

(6) See Chapter 22 for pipe material schedule.

b. *Vents*.

(1) Vents should be provided as required by the IPC.

(2) Termination of vent stacks is normally above roofs. However, other code termination locations may be acceptable subject to architectural approval.

(3) Minimum slopes noted above for drains are also applicable to horizontally oriented runs of piping vents.

c. *Sanitary System Configuration*. Refer to Figure 24–3 for typical sanitary system configuration.

26–7. Sewage Treatment

a. General.

(1) Sewage treatment should generally be combined into one facility for the entire project. The facility is frequently located away from the powerhouse and coordination is required.

(2) Sewage treatment for the powerhouse design is usually limited to collecting and possibly pumping the raw sewage to the treatment facility/plant.

(3) When a powerhouse location is most practical, the treatment plant is included in the powerhouse design.

(4) USACE policy is to comply with federal and state sewage treatment requirements. The requirements vary considerably from project to project, in part due to site differences, but to a greater extent from revisions in the federal and state regulations. The design office should obtain the earliest possible approval for proposed facilities at each project to permit orderly development of piping, pump, and treatment design.

b. Septic Tanks.

(1) *General*. Septic tanks are the preferred treatment facility from design, cost, operation, and maintenance standpoints, and should be provided whenever an approved leaching field location is reasonably available. Septic tank effluent discharge directly to tailwater is not permitted.

(2) *Location*. A septic tank may be located either in the powerhouse or away from the powerhouse. In-house tanks are normally located in mass concrete at a low elevation providing gravity drainage from all fixtures. The location should permit access to the tank through manholes and adjoining space for installation and servicing of effluent pumps, sludge pumps, and chlorinating equipment.

(3) *Design*. Septic tank design and chlorination equipment should conform to state code requirements for the state in which the leaching field is located. Mechanical design responsibility includes coordination of piping, pump, chlorination, and valve locations with a suitable tank location.

c. Other Treatment Facilities. Facilities other than septic tanks are normally a civil engineering responsibility and involves one of several types of secondary or tertiary treatment processes. Mechanical design responsibility includes piping, valves, pumps, ejectors, chlorination, and coordination.

d. Non-Gravity Sewage.

(1) Where it is impractical to move raw sewage from the powerhouse collection point to the treatment facility by gravity flow, a duplex pneumatic sewage ejector or duplex non-clog centrifugal pumps capable of passing a 2-in (5 cm) sphere should be provided.

(2) Duplex non-clog pump installations require the following:

(a) All sewage must be screened before entering the pump.

(b) The screen must be self-cleaning with each pump operation.

(c) Pumps must be the wet pit type.

(d) The pump control system must provide for automatic lead-lag switching of the pumps on every start.

(e) Each pump must be sized to handle the rated system inflow.

(f) The above requisites can be accomplished by connecting the inflow line from the powerhouse sanitary system into the pump discharge lines with commercially available equipment and collecting the solids on the discharge line screen of the off pump while the liquids are backed through the off pump to the sump. The subsequent pump operation clears the screen.

(3) Valving, screens, and interconnections should follow manufacturers' recommendations.

(4) The smallest capacity pneumatic sewage ejectors and non-clog pumps tend to be higher than the required capacity for most powerhouses, and the specifications should permit the contractor the option of supplying either ejectors or non-clog pumps.

e. Sludge and Effluent Provisions.

(1) *General*. Effluent should be pumped via fixed piping to leaching fields or, in the case of approved secondary or tertiary treatment plants, may be pumped or discharged by gravity to tailwater through an underwater discharge. Sludge is normally pumped via fixed piping to a deck hose valve accessible to trucks. Minimum line size should be 3 in (7.62 cm).

(2) *Pumps*.

(a) Sludge and effluent pumps should have not less than a 1.5-in (3.81 cm) inlet and outlet and should pass a 1-in (2.5 cm) sphere.

(b) Where both effluent and sludge pumps are required for the same treatment plant or septic tank, it is preferable to provide identical pumps to allow each pump to serve as backup for the other. Backup operation is temporary only and should be provided for by hose and hose valves, tied to the suction and discharge piping of each pump rather than fixed piping.

(c) Alternate backup provision is a spare pump and piping connections suitable for rapid exchange of pumps.

(d) Control of effluent pump should be automatic and provided by either float or bubbler control.

(e) Control of sludge pumps should be manual and should include an adjustable timer switch to limit pump operation to the normal sludge pumping time requirement.

(3) *Line Losses*. Pumping head computations for sludge pumps should reflect the higher line losses due to entrained solids. Computing overall losses on basis of water and using a multiplying factor of 2.5 to 3 is satisfactory for most powerhouse applications. If velocities exceeding 5 fps (1.5 mps) are encountered, the factor may be reduced to 1.5.

Chapter 27
Unwatering and Drainage Systems

27–1. General

a. The unwatering and drainage system provides the means for unwatering main unit turbines and their associated water passages for inspection and maintenance purposes, as well as the collection and disposal of all powerhouse leakage and wastewater other than sanitary.

b. The provisions for equalizing (unit filling) are closely related to unwatering and are included in this chapter.

c. The safety of personnel and plant is a vital concern in this system and should have continuing priority throughout the design.

d. The legal regulations and requirements regarding discharges from a project into waters of the United States have evolved since the dams were originally built, and will continue to do so. For example, the temperature of discharged water can be considered a pollutant for projects covered by a National Pollutant Discharge Elimination System (NPDES) permit. Designers should work closely with District Office of Council and Environmental Compliance Coordinators to ensure all unwatering and drainage systems meet all current laws and regulations.

e. Figure 27–1 at the end of this chapter shows an example of an unwatering-drainage system for a typical 2-unit powerhouse with Francis runners.

f. Figure 27–2 at the end of this chapter shows an example of an unwatering-drainage system typical for a multiple unit plant with Kaplan runners.

27–2. Unwatering System

a. *General*.

(1) The principal volumes to be unwatered in all powerhouses are the spiral case, draft tube, and the volume downstream of the headgates or penstock valve.

(2) Unwatering of non-powerhouse facilities. Some projects include extensive fish passage facilities with large volumes of water in pumps, channels, and conduits to be unwatered. It is acceptable to use the powerhouse unwatering conduit, sump, and pumps for unwatering of fishway conduits, channels, and pumps as well as other facilities in or adjoining the powerhouse. However, frequency of use, length of lines, line plugging, safety, required unwatering time, cost, and possibility of conflicting unwatering schedules should be carefully evaluated. Portable equipment is frequently a preferable choice.

(3) Use of the unwatering facilities for construction requirements or for maintaining skeleton (future) powerhouse bays in an unwatered condition should not be planned. Questionable condition of equipment and fouling of lines with construction debris after such use is usually experienced.

b. *Unwatering Procedure*. A typical unwatering procedure after shutdown is as follows:

(1) Closing of the headgates or penstock valve;

(2) Drainage of all unit water above tailwater to tailwater elevation through the wicket gates, and spiral case or spiral case extension drain;

(3) Placement of draft tube bulkheads or stoplogs;

(4) Draining the remaining unit water to sump, through the draft tube drain, with the sump pumps operating.

c. Unwatering Time. Aside from safety, the required elapsed time for completing a unit unwatering is the major factor in unwatering system design. Unit downtime is usually a value justifying facilities to accomplish unwatering in 4 hours or less. This can mean that in a typical plant, all necessary valve, gate, and stoplog or bulkhead operations should be done in approximately 1 hour and draining of the pumping system in approximately 3 hours.

d. Spiral Case Drains.

(1) Spiral case drains should normally be sized to preclude draining of the spiral cases from becoming a controlling factor in total unwatering time. Oversizing to the point where mis-operation could result in excessive unseating head and damage to draft tube stoplogs or tailrace structure must be avoided, particularly in plants where opening the drain valve is part of the equalizing procedure. With properly sized drains, the unseating force on the draft tube stoplogs results in enough leakage to prevent a damaging pressure rise.

(2) The drains should normally be provided with manually operated rising stem-gate valves for control. However, portable or fixed power operators can be justified on the larger sizes. Typical sizes in existing plants are in the 4-in. (102-mm) to 8-in. (204-mm) range for small Francis unit plants and in the 16-in. (406-mm) to 20-in. (508-mm) range for large Kaplan unit plants. Maximum flow velocities usually render butterfly valves unsuitable.

(3) The designer should be aware of the flooding hazard resulting from a failure in this line and provide a layout with conservatively rated components and in which alignment and necessary flexibility can be reasonably attained.

(4) Spiral case drains should discharge to the draft tube to preclude pool head on the unwatering sump. A connection for introducing station compressed air immediately upstream from the control valve to dislodge packed silt and debris is normally required.

e. Draft Tube Drains.

(1) *Draft Tube Drain Sizing*.

(a) Draft tube drains should be sized with consideration for leakage from the following: intake gates, intake valves, and structural relief drains; draft tube bulkheads or stoplogs; the required unwatering time; and the assurance of seating the draft tube bulkhead or stoplogs.

(b) With average design and workmanship on bulkheads, stoplogs, and guides, the 3-hour draining requirement usually results in a large enough draft tube drain to seat the bulkhead or stoplogs.

(c) A short drain line discharging into a large conduit and sump results in a high initial flow rate ideal for the seating requirement. Where drains are manifolded directly into the pump intakes, the individual draft tube drains tend to be smaller, and the maximum capacity of the entire system should be evaluated for the possibility of unseated leakage, plus other leakage, which equals or exceeds the drainage capacity.

(2) *Draft Tube Drain Valves*.

(a) Valves for the draft tube drains are usually either a submerged rising plug type (mud valve) or standard in-line rising stem-gate valves. The location of these valves

subjects them to a high potential of becoming plugged with silt and debris. Valve type should be chosen to minimize these risks and maintenance requirements.

(b) The rising plug type offers a drain line installation not subject to plugging from packed silt and no exposed components subject to flooding hazard failures. Its disadvantage is the head requirements, for large units with deep submergence are usually not within standard valve ratings, which result in nonstandard equipment. Attempts to upgrade standard valves usually cause problems in obtaining valves with adequate safety factors for all hydraulic forces and operator forces.

(c) Standard gate valves and operators are available as off-the-shelf items for installations in a dry pit location accessible to the embedded drain line, but the potential for line plugging between the draft tube and valve is disadvantageous. Short lines with compressed air blowout connections minimize problems when trying to clear a plugged valve. This type of valve installation is ordinarily restricted to smaller plants without an unwatering header or tunnel.

(d) For larger units with deep submergence, the preferred valve is either a standard design gate valve suitable for submergence in a draft tube recess or special design plug-type valve with design for the required head completely detailed in the contract drawings.

(e) Two valves should be installed in draft tube locations to provide unwatering capability with one valve inoperable, but required unwatering time should assume that both valves are operable.

(f) Powered operators, either portable or fixed, are usually justified for larger installations.

(g) Butterfly valves are generally unsuitable because of high velocities.

(3) *Pipe Header or Conduit*. Draft tube drains may be run individually to the unwatering sump in small plants but are usually discharged into a large pipe header or formed conduit leading to the sump in large plants. The formed conduit has definite advantages in large Kaplan unit plants as it can be large enough for inspection and cleanout, can form an effective addition to sump capacity, and is often more economical than a pipe header.

(4) *Flooding Hazard Precautions*. The flooding hazard precautions regarding spiral case drains are also applicable to draft tube drains.

f. *Unwatering Sumps*. Refer to paragraph 27–4 for unwatering sump requirements.

g. *Unwatering Pumps*. Refer to paragraph 27–5 for unwatering pump requirements.

27–3. Drainage System

a. *General*. The drainage system handles the following types or sources of drainage. Discharge is to tailwater either by gravity or by pumping from a drainage sump.

(1) Rain and snow water from roofs, decks.
(2) Rain, snow, and fire protection water from transformer pits.
(3) Leakage through structural cracks and contraction joints.
(4) Waste and process water from equipment.

b. Roof and Deck Drainage.

(1) Roof and deck drainage should normally be directly to tailwater by gravity. However, where the powerhouse forms a portion of the dam structure, it may be feasible to drain the intake deck to pool.

(2) Size of roof and deck drains should be based on the greater of applicable code requirements or maximum 1-hour rainfall figures for the area.

(3) A minimum of two roof drains per bay should be provided to minimize flooding from plugging.

(4) Deck drains should be located to eliminate standing water and should consist of short vertical runs of piping wherever practicable in freezing areas. Decks with open block-out type of rail installations should be provided with blockout drains.

c. Transformer Pit Drainage. Many dams were originally constructed so that flows from the transformer containment pits and, in turn, the transformer fire protection deluge system were directed toward the deck drains and eventually into the river. Since there is a high probability of these flows containing transformer oil, discharging this oily water to the river conflicts with the Clean Water Act and could result in a reportable spill. Measures should be taken to modify the transformer pit drains to prevent oily water from reaching the river. Measures to modify the pits should be coordinated with Chapter 29 and all applicable laws and regulations.

d. Powerhouse Leakage and Floor Drains.

(1) *Drainage Galleries*.

(a) Drainage galleries and other galleries with a wall in contact with water or a fill below high tailwater should be provided with a drainage trench. The trench should be sized and graded for maximum estimated leakage based on existing similar powerhouses. Unless located in grouting galleries, trenches should not cross contraction joints without provision of water stops.

(b) Conduits connecting the trenches to the drainage sump and the conduit entrances should be carefully designed to preclude overflow of the trench onto the gallery floor.

(c) Contraction joint drains should discharge visibly into the drainage trench to permit monitoring of joint leakage.

(d) A float-operated alarm should be provided to indicate flooding of the lowest gallery.

(2) *Oil Storage*. Oil storage and purifier room drains should be plugged so the room itself acts as containment. Small spills can be wiped up and large spills can be pumped out for proper disposal.

(3) *Battery Room*. Battery room floor and sink drains should be of acid-resisting material, have a minimum 2 percent slope, no pockets or traps, and can discharge directly to the sump or tailrace.

(4) *Other Floor Drains*. All other floor drains should be provided according to ASME B31.1, the International Plumbing Code, and as follows:

(a) All floor areas below average peak-flow tailwater, and all other floor areas subject to flushing, leakage from, or periodic disassembly of water-filled equipment or piping should be drained.

(b) Any drains that come from a source that can add oil to the water should not drain directly to tailwater, but should first be routed to an oil separator facility.

(c) The following areas are typical of most powerhouses, but the required areas of each powerhouse should be determined individually:

1. Turbine rooms.
2. Galleries.
3. Water treatment room.
4. Pump rooms.
5. Locker rooms.
6. Toilet rooms.
7. Machine shop.
8. Heating and ventilating equipment room.
9. Gate repair pits.
10. Gate and bulkhead storage pits.
11. Pipe trenches.
12. Elevator pits.
13. Rigging rooms.
14. Valve pits.

(5) *Location of Floor Drains*. Locating floor drains requires close coordination with structural and architectural requirements, but the following general considerations should apply:

(a) All areas where water is normally expected (such as leakage, rainwater, water from disassembly, flushing) should have floors with continuous slope to the drain location. Examples of these areas are around pumps, strainers, janitor closets, outside decks, shower rooms, unloading areas, and drainage galleries.

(b) In other areas with unfinished level floors, it is desirable to locate drains in the center of a 36–48-in. (914–1,219-mm) depressed area to assist in directing water to the drain.

(c) In finished areas (terrazzo, tile) where slope or a depressed area cannot be obtained, the architect should determine the drain location and elevation.

e. Waste and Process Water from Equipment.

(1) *Gravity Drainage*.

(a) Drainage should be collected and piped to the floor drains, sealed connections, or sight funnels. Open flows running horizontally across floors or drain lines should be avoided.

(b) Francis turbines are normally drained by gravity, and drainage from propeller turbines is normally pumped out of the turbine pits with pumps (headcover pumps).

(c) The following equipment waste and process water is normally drained to the sump through the drainage piping system by gravity:

1. Pump gland drainage.
2. Strainer drains.
3. Condensate.
4. Air compressor cooling water.
5. Turbine head cover leakage.

6. Heat exchanger.

7. Turbine pit liner drainage.

(2) *Pressure Drainage*.

(a) Wastewater from generator air coolers and bearing coolers are normally piped directly to the tailrace. Some powerhouses also require pressure drains for transformer cooling water and air conditioning cooling water.

(b) The point of discharge for pressure drains requires careful consideration as several factors are involved. These include the following:

1. Tailwater fluctuations.
2. Available head (where the source is pool water).
3. Pumping costs.
4. Pressure conditions in coils and other equipment.
5. Icing conditions.
6. Requirement for flap valves or other protective shutoff valves.
7. Line and valve maintenance.
8. Esthetics (visibility of discharge).
9. Fish passage channels.

(c) An optimum discharge location is above maximum tailwater for safety reasons. Where this is not practicable, a location above normal operating tailwater and the provision of a readily accessible shutoff valve at the point where the line becomes exposed in the powerhouse are preferred. A vented loop to prevent backflow from tailwater is satisfactory, but space requirements and the additional piping can make this provision impractical.

(d) Pressure discharge lines should be designed for maximum obtainable pressure conditions, and if an isolating valve is used, the effect of an inadvertent closure should be considered. Flap valves located below minimum tailwater are unsatisfactory because of inaccessibility for inspection and maintenance.

f. *Drainage Sumps*. Refer to paragraph 27–4 for drainage sump requirements.

g. *Drainage Pumps*. Refer to paragraph 27–5 for drainage pump requirements.

h. *Drainage Piping*.

(1) Drainage piping should be consistent with Chapter 22. Embedded drainage piping should be provided according to the following additional requirements:

(a) Embedding piping should be cast iron soil pipe.

(b) Horizontal turns should be long sweep.

(c) Vertical turns may be quarter bend.

(d) Minimum line size is 3 in. (76 mm).

(e) Slope in horizontal lines is preferably 2 percent and a minimum of 1 percent.

(f) Routing should be generally parallel with building lines to minimize interference with reinforcing steel and other embedded material.

(g) Lines crossing contraction joints require provision for flexibility.

(h) Lines more than one-third the thickness of wall or slab should not be embedded.

(2) Drains in lower powerhouse areas may be fitted with backflow valves to minimize flooding under adverse conditions. However, such devices are not considered as positive protection against backflow in system design.

i. Estimating Drainage Leakage.

(1) Leakage through contraction joints and cracks in floors and walls is usually the major uncertainty in estimating total drainage facility requirements. Where the powerhouse is a structure separate from the dam, 1 gpm/foot (1.32 lpm/meter) of powerhouse length is sometimes used. This increases appreciably when the powerhouse is integral with the dam. Drainage to the powerhouse from a separate intake structure frequently is routed to the powerhouse drainage sump, and this is subject to the same uncertainty as the powerhouse leakage itself.

(2) The most reliable estimate is one based on an existing powerhouse of comparable size, configuration, and head conditions. Information on existing designs and operational experience is readily obtainable from district offices and through review offices.

j. External Drainage. For some projects, it is expedient to route some of the drainage from the dam or other project facilities to the powerhouse drainage system. Such drainage should be limited to minor flows totaling not more than 10 percent of the estimated powerhouse drainage, since any significant addition to potential flooding of the powerhouse should be avoided. Estimated drainage from such sources are subject to many variables, and it is a responsibility of the powerhouse designer to verify the estimates.

27–4. Sumps

a. Provisions. Sump provisions in most projects require either joint usage in both the unwatering and drainage systems, or separate sumps with the unwatering sump serving as a backup or overflow for the drainage sump. Size and configuration specifications require close coordination with the planned pumping provisions and inflows to permit practical pump cycles with adequate backup and effective high-level warning provisions. Whenever space and reasonable cost permit, it is preferable to provide oversized sumps to allow more flexibility to accommodate unexpected leakage, additional or larger pumps, or revised operating procedures.

b. Drainage Sump. The drainage sump or joint unwatering-drainage sump should be located low enough to provide gravity flow from all drained areas under all dry powerhouse design tailwater conditions and up to the float-operated alarm, sump water elevation. Deviations from this requirement can occur in the case of certain low-drainage galleries deemed noncritical for short-term drainage interruptions. However, such applications should be discussed with review offices before proceeding with design.

c. Requirements for All Sumps.

(1) Sumps should be designed for maximum tailwater head with assumed pump failure and vents should be located above maximum tailwater elevation.

(2) Floors should be graded to a small sump within a sump to permit using a portable pump for maintenance unwatering the main sump.

d. Drainage Sump Overflow. When separate drainage and unwatering sumps are provided, the drainage sump should be provided with an overflow to the unwatering sump.

(1) The overflow typically is located slightly above the high-water-level alarm elevation. However, for any major rehabilitation of the sumps, evaluate whether sump configuration, flows, and operating procedures allow a low-level pass-through to be added. The purpose of the low-level “underflow” is to retain any oil in the drainage sump on top of the water, while allowing the unwatering pumps to assist if water reached high levels.

(2) Provide a flap valve to prevent flow from the unwatering sump to the drainage sump. The flap valve should be reasonably accessible for maintenance. It should be sized to bypass the drainage sump inflow capacity or unwatering pumps combined capacity to permit maximum utility in the event of an accident or flooding in the powerhouse.

(3) The drainage sump overflow should be above the lag pump “on” elevation and be provided with a check valve that has a pressure rating based on maximum tailwater.

e. Safety Pool. Some projects with separate sumps provide for a “safety pool” of water in the draft tube when work is being done on the turbine runners. This is usually accomplished by allowing the unwatering sump water level to rise and overflow into the drainage sump through a valved opening. Thus, a valved opening between sumps is required. Drainage pump capacity has to handle the increased flows from all leakage into the unwatering sump.

27–5. Pumps

The unwatering and drainage pumping provisions require, along with the sumps, consideration of their individual and joint usage requirements. Usually, more than one combination of pumps is practical for any application. However, the following general principles should be observed:

a. Pump Type. Pumps of the deep well water lubricated type are usually preferred. Water jet eductors can seldom be justified from an efficiency standpoint, and dry pit pump installations are less desirable in safety and cost considerations. Submersible motor and pump combination units mounted on guide rails permitting the pump units to be raised or lowered by the powerhouse crane have been used at several projects. Provisions are included for automatic connection to the pump discharge line. This design eliminates the long pump shafts and simplifies maintenance.

b. Pump Performance Characteristics.

(1) Sump configuration and automatic start-stop settings should allow a minimum of 3-minutes running time per cycle for all pump selections.

(2) Pumps should be suitable for operation at zero static head.

(3) Pumps should have continuously raising performance curves.

(4) Pump motors and controls should be located above average peak flow tailwater.

(5) Silent-type check valves should be used in pump discharge lines.

c. Pump Controls.

(1) Either pneumatic bubbler-type or float-type controls are satisfactory for pump control.

(2) A separate float type of control should be provided for the drainage sump (or combined drainage-unwatering sump) for high-water alarm.

(3) Automatic lead-lag with manual selection of the lead pump is preferred.

d. Pump Provisions. Where space is available, the preferred provisions should include the following: separate unwatering and drainage sumps, separate unwatering and drainage pumping provisions, and automatic overflow from the drainage sump to unwatering sump.

e. Pump Capacity. With separate systems, the drainage pump capacity should be divided between two pumps of the same capacity. Each should be capable of pumping a minimum of 150 percent of maximum estimated station drainage at an average peak-flow tailwater and with combined capacity to handle estimated station drainage at powerhouse design flood.

f. Two-Pump Capacity. With combined single-sump systems, the drainage and unwatering two-pump capacity should meet the stated minimum requirements for separate systems. The two pumps should pump from an in-sump manifold with valved connections from unwatering lines and a valved inlet from the sump. The manifold inlet valves should be manual, and design should be based on station drainage accumulating in the sump during an unwatering operation. A third manually controlled pump of the same capacity should be installed as backup for the drainage function. Suction for the third pump should be directly out of the sump, not through the header.

g. Backup Provisions. Whenever practicable, minimum piping (particularly embedded), sump capacity, and pump arrangement backup provisions should permit the addition of future pumping capacity.

h. Discharge Piping. Unwatering system discharge lines normally terminate above the average peak-flow tailwater. Therefore, reliance is on the discharge check valves for prevention of backflow at high tailwaters and permission of line and check valve maintenance at lower tailwaters. Individual pump discharges to the tailrace are preferable, but a single discharge header for combined unwatering-drainage pumps and a single header each for separate unwatering and drainage systems are usually more practicable to use.

27–6. Equalizing (Filling)

a. General. Equalizing is the process of refilling the water passageway after an unwatering event and creating equal hydrostatic pressure between the intake gate/penstock valve and the forebay and between the draft tube bulkhead and the tailrace. A variety of methods have been employed for equalizing, but two preferred methods are described below. Other methods involving equalizing headers or crossover connections are satisfactory in operation but introduce additional piping and valves along with increased flooding hazards in event of failure.

b. Gate Cracking. Gate cracking is the process of using the intake gate machinery or crane to slightly open the intake gate, thereby allowing water to flow into the unit at a relatively controlled rate. This process is commonly used at plants during equalizing and is described in the procedures below. The following is noted about gate cracking and related operations.

(1) Gate cracking should be avoided when the intake gates are equipped with upstream seals due to the possibility of gate catapulting during filling. The risk and consequences of gate catapult increase with the differential head across the gate.

(2) See Chapter 20 for additional details and discussion on load demand due to gate cracking on hoisting machinery.

c. Low Head Projects. Low head projects up to about 125 ft (38.1 m) usually have one or more intake gates and a set of draft tube bulkheads or stoplogs. Equalizing on these projects can be accomplished by the following process. Note that the entire operation takes place with the wicket gates closed and no additional piping or valves are required.

(1) Open the spiral case drain, crack the intake gates, and fill the draft tube to tailwater then lower the gates.

(2) Remove the bulkheads or stoplogs and close the spiral case drain,

(3) Crack open the intake gates again, filling the spiral case and intake, thereby equalizing to pool head.

d. High Head Projects.

(1) Higher head projects provided with a penstock valve typically have a bypass valve for equalizing pressure across the penstock valve. Equalizing on these projects can be accomplished by the following. Note that the entire operation takes place with the wicket gates and spiral case drain closed.

(a) Fill to tailwater using valves provided in the draft tube bulkhead or stoplogs. See below for additional information regarding the valves and their operation.

(b) Remove the draft tube bulkhead or stoplogs.

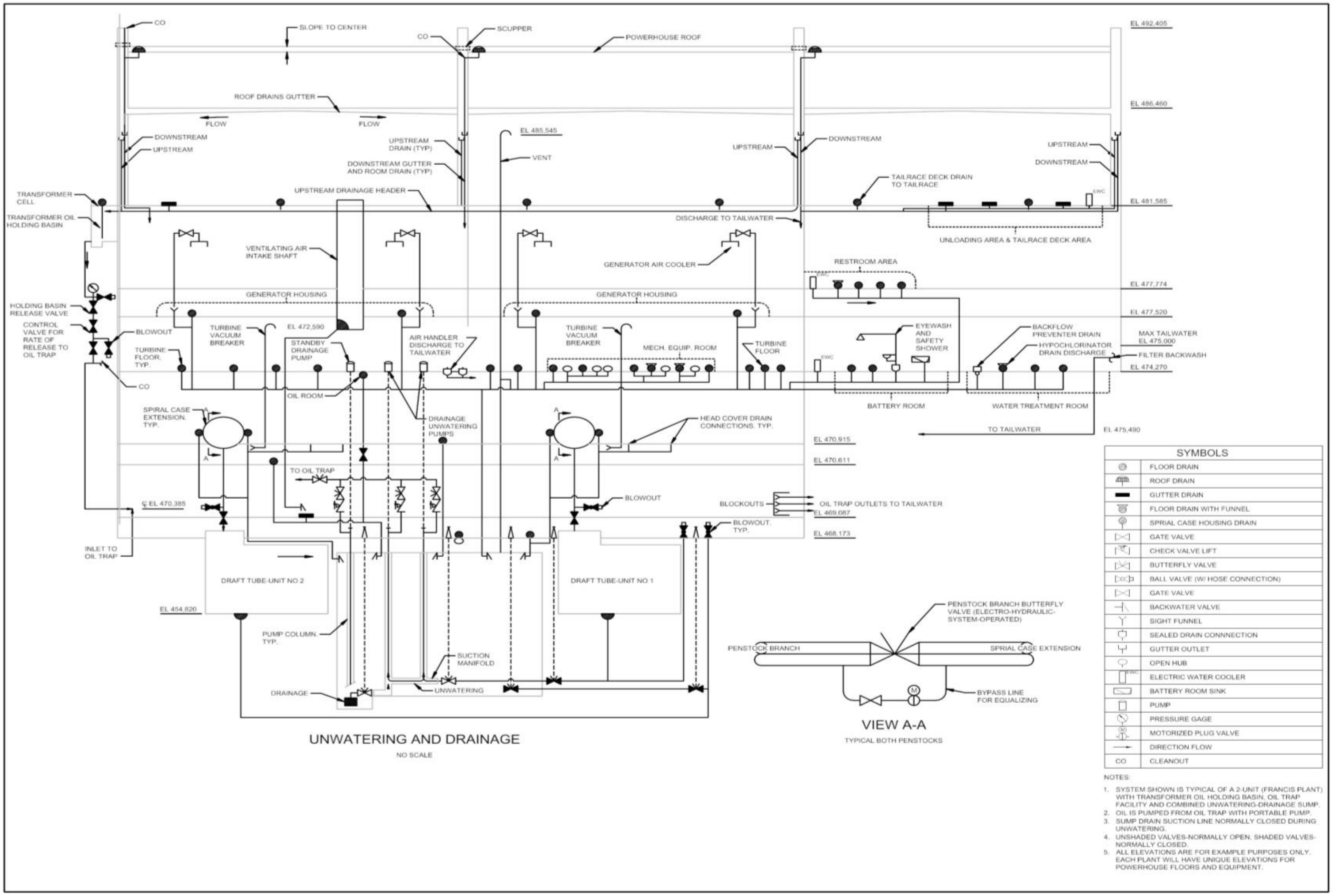
(c) Fill and equalize the spiral case through the penstock valve bypass.

(2) Additional equipment involved consists of one or more tag-line operated valves in a draft tube stoplog or bulkhead. The tag-line operated valves should be a balanced type of valve to permit convenient tag-line operation in both directions and should be located near the top of the bulkhead or stoplog. Valve sizes should be consistent with the unwatering time noted elsewhere in this chapter.

27–7. Venting

a. When a penstock valve is used, the spiral case requires an air and vacuum relief valve to permit filling and unwatering. This valve and line should be sized to prevent less than one-half atmospheric pressure developing in the spiral case and should open to release air under pool pressure.

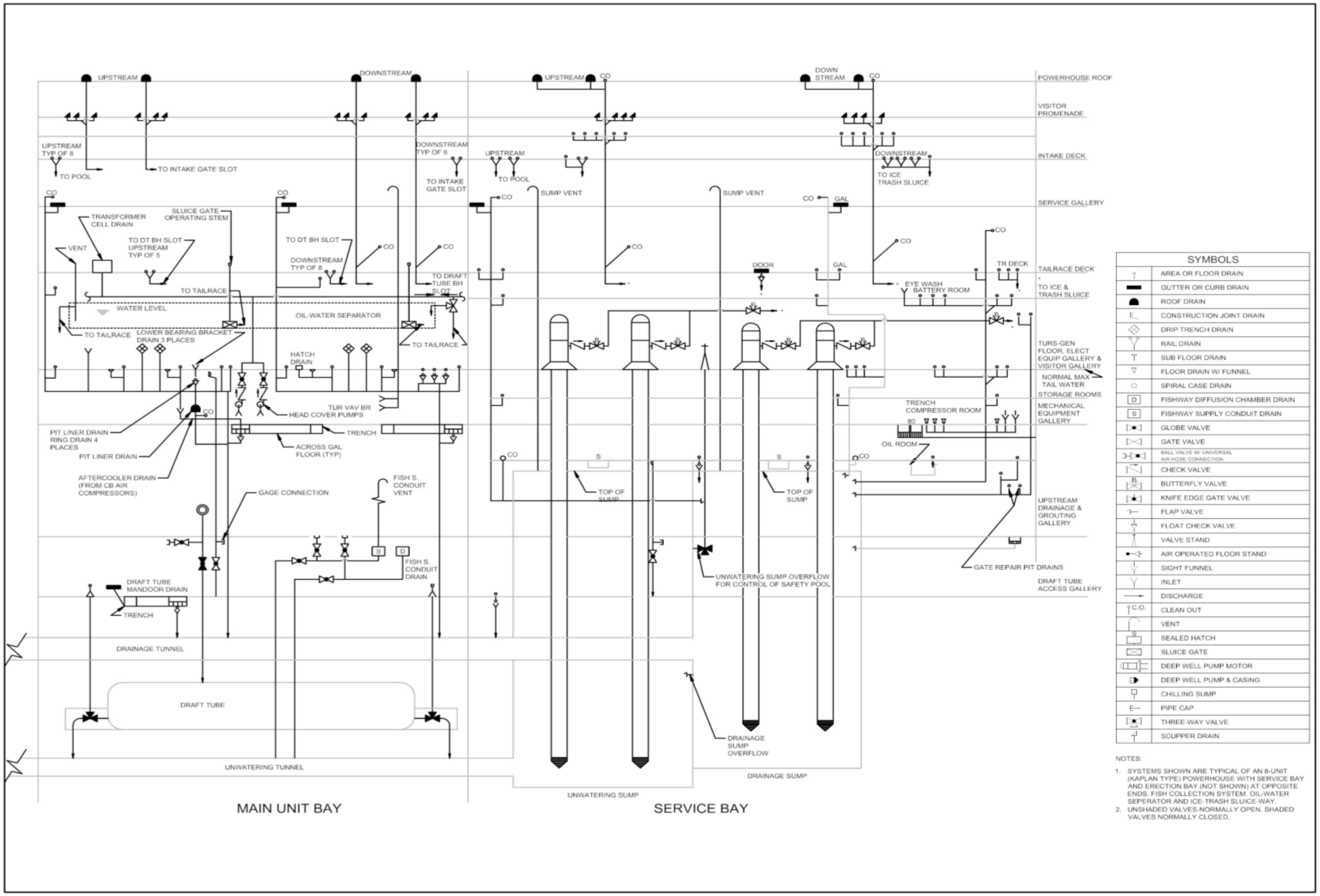
b. The takeoff should be from the top of the casing or spiral case extension, and the vent line should be provided with a cutoff valve located as close to point of takeoff as practicable. Termination should be in a screened opening, above maximum tailwater, and clear of personnel areas.



NOTES:

1. SYSTEM SHOWN IS TYPICAL OF A 2-UNIT (FRANCIS PLANT) WITH TRANSFORMER OIL HOLDING BASIN, OIL TRAP FACILITY AND COMBINED UNWATERING-DRAINAGE SUMP.
2. OIL IS PUMPED FROM OIL TRAP WITH PORTABLE PUMP.
3. SUMP DRAIN SUCTION LINE NORMALLY CLOSED DURING UNWATERING.
4. UNSHADED VALVES-NORMALLY OPEN, SHADED VALVES-NORMALLY CLOSED.
5. ALL ELEVATIONS ARE FOR EXAMPLE PURPOSES ONLY. EACH PLANT WILL HAVE UNIQUE ELEVATIONS FOR POWERHOUSE FLOORS AND EQUIPMENT.

Figure 27–1. Example unwatering and drainage system for a typical 2-Francis unit plant



NOTES:

1. SYSTEMS SHOWN ARE TYPICAL OF AN 8-UNIT (KAPLAN TYPE) POWERHOUSE WITH SERVICE BAY AND ERECTION BAY (NOT SHOWN) AT OPPOSITE ENDS. FISH COLLECTION SYSTEM. OIL-WATER SEPERATOR AND ICE-TRASH SLUICE-WAY.
2. UNSHADED VALVES-NORMALLY OPEN. SHADED VALVES NORMALLY CLOSED.

Figure 27–2. Example unwatering and drainage system for a typical large plant with multiple Kaplan units

Chapter 28
Machine Condition Monitoring

28–1. General

a. Hydro-electric turbine generators in the USACE fleet were typically not equipped with machine condition monitoring (MCM) systems because the technology was not available at the time these units were installed. Technologies have since been developed to dynamically monitor a wide range of machine conditions and parameters that provide feedback on the health of power generating units and can be used to make informed decisions regarding O&M of the unit. Use of MCM is expected to become more widespread with modernization efforts and improves ability to shift toward condition-based maintenance practices.

b. Designs are being considered for rewind with uprate of power output that increases forces on components, and operation is being modified from traditional steady state to more variable loading, which adds to stress cycles on components. These developments support the idea that collecting operational data by MCM systems on generating units allow more comprehensive condition assessments of main unit conditions, keeping them operational, and potentially preventing unscheduled outages.

c. Protection monitoring could also be considered as an alternative by taking a minimalized approach to protecting the generating unit. This type of installation monitors only shaft vibration at the turbine guide bearing, providing only an output signal with alarm at pre-determined critical levels for preventing damage to the unit. This has also been referred to a critical vibration monitoring (CVM).

28–2. Justification

a. There are numerous case studies available that describe quantifiable benefits from installing MCM systems on hydroelectric turbine generator units. These cases tend to involve new and refurbished units of various sizes. The number of sensors and extent of complexity is flexible for MCM systems, which makes implementation cost effective for most cases.

b. For turbine-generators with suspected or known dynamic stability problems, the cost of a machine monitoring system is small when compared to the generation revenue gained by extending the time until an outage to repair is required, or the avoided outage costs of preventing a failure. For example, installing air gap sensors can warn to avoid stator rotor impact because the dynamic proximity of the two surfaces is less than the static measurements taken during maintenance procedures.

c. An evaluation of the costs and benefits of MCM should be performed for each plant. When evaluating whether to install an MCM system, account for the burden on the project O&M staff for the labor of monitoring and analyzing data output. Offsetting the cost increase for monitoring is the potential for reduction of time-based maintenance outages by adapting to condition-based scheduling for maintenance. The evaluation should calculate the reduction of lost power revenue and costs associated with maintenance labor. If these cost reductions are greater than the labor costs associated with monitoring the MCM system, then an MCM system should be pursued.

(1) *New Machines*.

(a) For new turbine-generators, including an MCM system is recommended. Not only is the incremental cost of a system low when compared to the cost of the new turbine-generator, but the benefits of catching design or erection problems early and ensuring that the Contractor accomplished the commissioning performance requirements could be substantial (in addition to having continuous monitoring during the warranty period and beyond).

(b) At the very least, providing a new machine should require the Contractor to produce a commissioning “baseline” report to show successful completion of task tolerances set for balancing, alignment, bearing adjustment, and shaft vibration. This report can be completed by collecting data with two temporary shaft sensors at each guide bearing.

(c) However, temporary shaft sensors do not provide rotor rim shape, stator core shape, and dynamic air gap values because the necessary air gap sensors are not easily installed and removed. Alternately, air gap sensors could be required for the commissioning report at additional cost, and then abandoned in place.

(d) One permanently installed MCM system with shaft sensors at each bearing and air gap sensors will provide data for a “baseline” report. The cost is estimated to be 25 percent higher to install the same permanent system on an existing unit outside of a rewind or refurbishment. Installing a permanent MCM system also ensures that the data readings taken throughout the life of the unit for troubleshooting and condition assessments are comparable to the commissioning baseline.

(2) *Refurbished Machines*. The benefits of installing a MCM system on turbine-generators during refurbishment are similar to those for new machines, with the addition of ensuring that problems to be addressed in the refurbishment were resolved and stay resolved. To recap, installing a permanent MCM system while the unit rotor is removed during the refurbishment should provide a cost savings as compared to taking the unit out of service specifically for the purpose of an MCM system installation.

(3) *Machines with Known Problems*. MCM systems can provide valuable information about the dynamic behavior of turbine-generators with known or suspected dynamic stability problems. Installation helps to maximize their service life and defer repair or replacement costs. Even if the dynamic performance of a machine is poor, knowing under what conditions the performance is best and being able to detect degradation in performance can allow continued operation while minimizing the probability of a failure.

(4) *Other Machines*. Operating turbine-generators that have undergone less comprehensive refurbishments (such as new runner or rewind with or without a core) may also benefit from having the information that a MCM system can provide. While it is true that many turbine-generators operate reliably for many years without any degradation detected by machine condition monitoring systems as described herein, learning about such degradation as it develops rather than after it has become severe is expected to reduce repair costs.

d. For additional information and reasoning, refer to Hydraulic Plant Life Interest Group (HPLIG) CEATI report number T192700-03/106. This report provides justification perspectives based on unit power output that may limit the return on MCM investment:

(1) Small hydroelectric generating units producing less than 25 MW should be outfitted if the unit reliability is critically important to a portion of the grid and for other justified reasons. If the small unit is not critically important, then only protective monitoring is recommended.

(2) Medium units, between 25–100 MW, are eligible for a range of implementation, from protective monitoring to a medium-sized MCM system.

(3) Units larger than 100 MW fall in the large category and may be justified to have a full MCM system implemented.

(4) Black start and pump storage capabilities contribute additional factors in criticality of units that positively influence the decision to implement MCM.

28–3. Scope

For the purposes of this chapter, MCM refers to all equipment used to collect, process, and record data pertaining to the dynamic operations of hydroelectric power generating units that are not already part of typical SCADA systems. A wide variety of options has been considered, and this chapter recommends those that offer the most information at a manageable cost or with a reasonable return on investment. The non-recommended options are also described, along with reasons why these may be implemented for deliberate cases.

a. Keyphasor.

(1) This proximity sensor is required on every installation to correlate measurements with shaft rotations. Data acquisition modules usually have one or two dedicated input connections specifically for this that are not part of their input channel count.

(2) Installation requires placement of a permanent target attached to the shaft such that the sensor detects the target once per rotation. The recommended location is at the turbine guide bearing housing for ease of access. The location of a target on the turbine shaft and the keyphasor on a support bracket should be aligned to trigger a signal coincidental with pole #1 being upstream. Some data analyzers have built-in flexibility by designating a phase shift to the signal.

(3) Sensor and related equipment may become submerged under water due to potential local flooding in the turbine pit. During such event, the sensor and equipment may temporarily fail to produce a signal but should be fully functional again after drying out and being restarted, if needed.

(4) On generator-pump units, there should be two sensors and two targets to align the leading edge of the target with pole #1, dependent on direction of rotation.

b. Time Synchronization.

(1) MCM data collection must be time synchronized using the same time standard as used by the SCADA system. Matching exact times is important when determining how the machine is affected by specific events. For example, an input command to change power production level results in a change of wicket gate position, which may cause a temporary spike in vibration. Without matching times, the person analyzing data is likely to waste time looking for the cause of the vibration.

(2) Typical installation relies on duplicating the time code standard signal that is used for the SCADA system and connecting that signal to the data acquisition module for each unit or at the server, depending on data collection and storage methods.

c. Parameter Data from SCADA.

(1) Correlation of machine operating data to that of the monitoring system is recommended for all installations. Collecting this data requires duplicating the information signals and making it available to the monitoring system for coincidental file storage. Alternately, the monitoring data could be stored on the SCADA historian server. Selecting the preferred file storage method should consider file storage capacity, data transfers, communication equipment, and accessibility for data analysis by the trained person.

(2) A wide range of parameter data is useful, such as:

(a) Guide bearing temperature.

(b) Thrust bearing temperature.

(c) Stator winding temperature.

(d) Stator air temperature.

(e) Wicket gate position.

(f) Turbine blade angle (Kaplan only).

(g) Power (MW).

(h) Frequency (Hz).

(i) Forebay and tailwater levels (or net head).

d. Protection Monitoring.

(1) This low-cost option provides an alarm at critical levels of turbine shaft vibration to protect the turbine end of the machine from serious failure, but it does not provide any data readings. The sensors of this small system should be connected to a simple analyzer, which should include the ability to produce output signals for annunciation or alarming if critical values are detected. The analyzer should be programmable for setting the pre-determined warning and alarm levels.

(2) Determine whether the reason for an annunciation will be reviewed by a trained individual or an operator before ordering a unit out of service. This standard operating procedure, which includes trained human intervention, could save the machine from unnecessary unplanned outages.

(3) Monitoring data and machine design parameters should be well understood before establishing alarm setpoints and connecting the protection output signal directly to shut down the generating unit. Before implementation, alarm setpoints should be tested, adjusted, and filtered for some time over the full range of operational conditions to minimize false trips.

(4) Installation involves two non-contact proximity probes, orthogonal to each other, at the turbine guide bearing. One of the two probes is aligned on the upstream side of the shaft and aimed radially toward the shaft. The second is positioned 90 degrees from the first, in the direction of shaft rotation, and aimed radially at the shaft.

e. Shaft Vibration.

(1) This arrangement is an expanded version of the protection monitoring described above by providing shaft vibration and shaft movement information local to all guide bearings. Other conclusions may be drawn on further review of the data, such as lack of bearing lubrication, excessive bearing runout or skating, shaft rub, bearing wear, shaft misalignment, and rotor unbalance.

(2) Typical instrumentation arrangements for shaft vibration monitoring involve the installation of two non-contact proximity probes, orthogonal to each other, at each bearing location on the generator and turbine shafts. One of the two probes is aligned on the upstream side of the shaft and aimed radially toward the shaft. The second is positioned 90 degrees from the first, in the direction of shaft rotation, and aimed radially at the shaft. On a typical vertical unit with three guide bearings, there are six sensors for this purpose.

f. Generator Air Gap.

(1) This arrangement provides static and dynamic measurements of air gap, rotor circularity and concentricity, and, with additional processing, stator circularity and concentricity. Inferences about rotor rim deformation, pole movement, stator core and frame growth, and other machine dynamics can be made as well.

(2) Multiple non-contact sensors placed on the inner surface of the generator stator core are used to measure the generator air gap during static position and dynamic operation. Sensors are secured with epoxy to the stator bore, which may or may not require the removal of one rotor pole, when done with rotor in place.

(3) For stator core inside diameters less than 16 ft (4.9 m), use a minimum of four upper sensors at 90-degree separation and sometimes a fifth sensor at a lower level.

(a) For stator core inside diameters between 16 and 24 ft (4.9 and 7.3 m), the installation requires six upper sensors at 60-degree separation and sometimes a seventh at a lower level. The number of upper sensors depends on the rotor diameter. The addition of a lower sensor is recommended only for rotors taller than 4 ft (1.2 m) because this helps determine if rotor poles are leaning or not.

(b) Stator core diameters from 24 to 30 ft (7.3 to 9.1 m) require a minimum of eight upper sensors at 45-degree separation plus a ninth sensor at the lower level. The same guidance as described in the prior paragraph for upper and lower sensors applies.

(c) Extremely large diameter, greater than 30 ft (9.1 m), and more than 6 ft (1.8 m) tall units may require at least 12 upper sensors and 12 lower sensors.

g. Thrust Bearing.

(1) Not typically included with MCM installations on vertical USACE generating units. Installation is recommended when units have a history of thrust bearing wipes, concerns with oil film thickness at thrust shoe contact surfaces, or when needing to establish quantitative severity of axial vibration.

(2) Typical location of at least two proximity sensors may be mounted on the structural support for the thrust bearing housing to measure relative movement between sensor tip and the machined collar of the shaft. Alternately, the sensors may be positioned in thrust shoes and measuring gap to the thrust collar. If both locations are not feasible, then an accelerometer mounted on the structural support may measure the vibration that is induced into the support structure, but it cannot determine lift.

h. Stator Core Vibration.

(1) Not typically included with MCM installations on vertical USACE generating units. Installation is recommended when needing to establish quantitative severity of vibration and verify frequency of vibration. This can also be used to determine if there are loose laminations that resulted from ineffective core wedges or clamping bolts.

(2) Installation of accelerometers are normally on the back side of the core. Spacing and quantity depends on the type of vibration and suspected waveform. The

recommended initial approach is to start with one sensor at each frame joint and one sensor at each midpoint of frame segments. Some vendors offer a daisy chain system that includes as many as 50 sensors on a single channel.

i. Stator Core Position.

(1) Not typically included with MCM installations on vertical USACE generating units. Installation is recommended when needing to confirm quantitatively the relative movement between stator core and stator frame.

(2) Installation of proximity sensor is mounted on inside of stator frame such that the sensor measures distance between sensor tip and back side of core in the radial direction.

j. Stator Frame Vibration.

(1) Not typically included with MCM installations on vertical USACE generating units. Installation is recommended when needing to establish quantitative severity of vibration and verify the frequency of vibration.

(2) Installation of accelerometers should be on the outside of the frame. Spacing and quantity depends on the type of vibration and suspected waveform. The recommended initial approach is to start with one sensor at each frame joint and one sensor at each midpoint of frame segments, aligned with stator core vibration sensors.

k. Stator Frame Position.

(1) Not typically included with MCM installations on vertical USACE generating units. Installation is recommended when needing to confirm quantitatively the relative movement between stator frame and foundation. This position feedback can be used to confirm quantity of movement at radial dowels.

(2) Installation of proximity sensors is mounted on the foundation (mass concrete) outside of stator frame such that the sensor measures distance between sensor tip and outside of frame in the radial direction.

l. Blade Tip Clearance.

(1) Not typically included with MCM installations on vertical USACE generating units. Installation is recommended for Kaplan turbine units that are experiencing reduced diameter of the draft tube as a result of concrete growth due to alkali aggregate reaction (AAR). Installation is not applicable to Francis units but is similar to labyrinth seal clearance sensors.

(2) This installation requires at least one proximity probe mounted in the draft tube lining at centerline of blades elevation. Multiple sensors provide more assurance and assist with centering of turbine within the draft tube as concrete on one side may grow more than another. Installation of these sensors is costly and involved because it requires mounting sensors through embedded features of the turbine liner and routing cables via solid foundation concrete.

m. Labyrinth Seal Clearance. Not typically included with MCM installations on vertical USACE generating units. When implemented, these sensors can be used to determine proper clearance at the upper and lower non-contact seal surfaces of a Francis unit runner. Not recommended because labyrinth seal clearance is rarely a problem that needs to be monitored continuously. Also not recommended since installation of these sensors is costly and involved because it requires mounting sensors through embedded features adjacent to the turbine runner.

n. *Absolute Bearing Vibration*.

(1) Not typically included with MCM installations on vertical USACE generating units. Installation is recommended when needing to confirm quantitatively the rigidity of the support structure to which the bearing housing is attached. Data may also be used to determine how much impact energy is being exerted on the bearing housing.

(2) This installation requires an accelerometer with at least one axis in the direction of anticipated motion mounted on the bearing housing or support structure. A single axis aligned with the shaft is applicable at the thrust bearing. When monitoring a shaft guide bearing for radial displacement, there should be two accelerometers, each with one axis of motion detection, or one sensor with two axes. The axes of motion should be aligned radially to the shaft and bearing bore.

o. *End-Turn Vibration*.

(1) Not typically included with MCM installations on vertical USACE generating units. Installation is recommended for units with extensive failures of insulation or brazed connections at stator coil end-turns. Repair projects related to end-turn repairs and stator core vibration studies may present an opportunity to implement these sensors and monitor the repairs.

(2) This installation requires an accelerometer with at least one axis in the direction of anticipated motion (radial) mounted directly onto the end-turn. Accelerometers with fiber optic cables are recommended for this application because they are designed to function in close proximity to high voltage. The number of coils to monitor depends on the grouping used to secure the end-turns and should at minimum have two sensors per circuit.

p. *Wicket Gate Shear Pins*. Not typically included with MCM installations on vertical USACE generating units. Installation is recommended for units with repeated failures of wicket gate link pins and design changes to link pins or their bushings. Implementation should consider a daisy chain method that connects all the pins to a single cable and provides a single data signal confirming the integrity of all pins. The failure of one pin should trigger an alarm.

q. *Draft Tube Cavitation*.

(1) Not typically included with MCM installations on vertical USACE generating units. Installation is recommended for units with known severe cavitation problems that frequently require extensive and expensive repair outages. The data is difficult to interpret and should be analyzed by a trained expert. Detecting cavitation is the first step, determining the location of the cavitation is the next step.

(2) This installation requires at least one ultrasonic probe that penetrates the head cover and is aligned with the axial direction of the turbine shaft. Multiple sensors provide additional coverage and may detect more localized cavitation activity. Consideration should be made to use appropriate frequency range to detect high order content.

r. *Draft Tube Vortex*.

(1) Not typically included with MCM installations on vertical USACE generating units. Installation is recommended for units with known vortex problems in the draft tube area that are severe and require investigating or monitoring to reduce their impact on the longevity of unit operability. Monitoring may also find acceptable operating conditions where vortex effects are minimal.

(2) Depending on the type of suspected vortex, this installation may require a combination of accelerometer(s) and pressure transducer(s). At least one accelerometer should be mounted onto the head cover with at least one axis aligned with the axial direction of the turbine shaft. Multiple axes and sensors provide additional coverage and may detect more localized vortex activity. The addition of pressure transducers located near the suspected vortex area (below the runner) may also be required to correlate and analyze data.

s. Draft Tube Pressure.

(1) Not typically included with MCM installations on vertical USACE generating units. Not recommended because USACE generating unit draft tubes were originally provided with pressure transducers that have since been connected to control or other monitoring systems. Considerations and justification could be made to reroute or duplicate the transducer signal to an MCM system.

(2) Installation of new transducers at new locations may be justified if there is need to monitor pressure at a specific point in the draft tube that was not originally supplied. Installation of new sensor(s) is costly and involved because it requires mounting sensors through embedded features of the turbine liner and routing cables via solid foundation concrete.

t. Head Cover Vibration.

(1) Not typically included with MCM installations on vertical USACE generating units. Installation is recommended for units with known vibration problems where monitoring is warranted because of severity. Further investigations are required to determine the cause and solution that may be the result of undesirable flow through the turbine associated with cavitation and vortexes.

(2) This installation requires at least one accelerometer mounted on the head cover and one on the turbine guide bearing housing, because one may influence the other. The accelerometers should have at least one axis aligned with the axial direction of the turbine shaft. Multiple sensors and multiple axes provide additional coverage and may show that vibration is not uniform across the head cover.

u. Partial Discharge.

(1) Not typically included with MCM installations on vertical USACE generating units. Installation of stand-alone, partial-discharge monitoring instrumentation is standard practice as part of USACE generator stator rewinds. The systems installed have wide acceptability, are used and understood by dozens of projects, and may not be compatible with commercially available MCM systems.

(2) The stand-alone partial discharge monitoring instruments include sensors and cabling that terminate inside a junction box on the generator barrel for periodic inspection by connecting to a specialized portable analyzer. These systems should remain independent. The data is unique, requiring a special skillset and software to interpret and should be analyzed by a trained expert. Detecting discharge levels is a first step, then determining the location of the discharge is more complex.

v. Rotor-Mounted Air Gap. Not typically included with MCM installations on vertical USACE generating units. This device can be used to verify stator core shape and to find loose wedges that may result in coil movement. Not recommended for implementation because the device relies on battery power that has limited time span, on the order of days.

w. Pole Face Temperature. Not typically included with MCM installations on vertical USACE generating units. When implemented, this sensor can be used to detect several possible pole problems (amortisseur bar problems, higher than expected pole face currents, etc.). Not recommended for implementation because pole failures and overheating have not been a common problem and the generating unit can continue to operate with a single failure. Rotor pole problems are typically discovered during annual maintenance outage.

x. Magnetic Flux. Not typically included with MCM installations on vertical USACE generating units. When implemented, this sensor should be located directly next to an air gap sensor for correlation and comparison. The data can be used to detect a failed rotor pole (turn insulation). Not recommended for implementation because pole failures are not common, and the generating unit can continue to operate with a single failure. Rotor pole insulation failures are typically discovered during annual scheduled maintenance outages.

y. Wicket Gate Vibration. Not typically included with MCM installations on vertical USACE generating units. When implemented, this technology can be used to determine the severity of effects that cavitation and flow vortexes can have on wicket gates. Not recommended for implementation because wicket gate vibration is often not a problem that needs to be monitored.

28–4. Equipment

a. Sensors.

(1) *Proximity Probes*. This non-contact technology measures distance from tip of sensor to the nearby object. There are two primary types of proximity probes, capacitive and inductive. Both are acceptable for the scope of machine condition monitoring. Both have their pros and cons; however, these rarely affect implementation on hydroelectric generators.

(a) The capacitive probes use a sensing element made from a piece of stainless steel that generates the electric field used to sense the distance to the target. Electronics are connected to the sensing element such that typical output signal from a sensor is 4-20 mA for the rated distance range of the sensor.

(b) The inductive probes use an AC in the sensing coil at the end of the probe to induce eddy currents in the target material that produces a voltage output proportional to the change in distance between the probe and target. The typical output signal from this type of sensor is -10 to 10VDC. Other voltage ranges are also available, but are not interchangeable and require tuning and recalibration on installation.

(2) *Accelerometer*. These sensors are applicable for measuring acceleration and their signal can be integrated mathematically to establish velocity. The sensor should be mounted securely against the equipment feature it is meant to measure.

(a) The most practical accelerometers for use in hydro turbines are piezoelectric devices that produce a proportional electronic signal when stressed by vibratory forces and exhibit unmatched long-term stability.

(b) Accelerometers are not recommended as a suitable means for primary detection of turbine shaft vibration and displacement because some accuracy is lost when operating at the 1X frequency of a typical hydro machine. Measuring sub-synchronous fluid film instabilities such as oil whirl and oil whip requires accurate

measurement down to 0.2 Hz for a 1 Hz rotational speed machine. This cannot be done accurately with common accelerometers.

(c) Accelerometers could be used as supplemental data to determine bearing housing vibration and deduce the absolute shaft movement local to that bearing. In addition to the guide bearings, these sensors are applicable for measuring acceleration and velocity at head covers, stator cores, stator frames, end-windings, and upper brackets.

(3) *Air Gap*.

(a) This technology uses a capacitive sensing wire built into a pliable housing (presumed soft durometer silicon) that can be attached to the stator bore with epoxy. The sensors are immune to magnetic fields up to 1.5 Tesla and immune to deposits of oil and carbon dust. The sensor should be capable of an operating temperature range equal to that of the generator air housing.

(b) Due to the non-linear signal response over the range in gap distance, the sensor readings need to be pre-processed by a linearized output signal conditioner.

(c) Any set of sensor cables is required to be made to identical lengths at the factory because the cable wire itself is part of the total resistance and are not to be modified at any time.

b. Data Acquisition Hardware.

(1) *Measurement Displays*. Data acquisition and analysis software should be capable of displaying measurements according to industry standards specific to North America where units of displacement should be in mils (µm) peak and peak-to-peak, velocity in mils per second (mm/sec), root-mean-square (RMS), acceleration in g, peak, and frequency in Hertz (Hz).

(2) *Monitoring Unit*.

(a) The monitoring unit or module should perform various types of synchronized measurements and processing (sampling, one-turn, multi-turns, alarm, trending). The module should be capable of processing incoming data and storing low-resolution data from at least one month of operation. The module should also be capable of periodic data transfers from memory and capable of collecting high-resolution data (at least 8,000 samples/second per channel for a short period).

(b) When connected to a server, the data transfers and high-resolution collection should be accomplished at the server. One form of low-resolution data consists of data from a single sensor that has been averaged over a specific number of rotations (like one averaged value per 10 rotations) to reduce memory usage. Low resolution may also be accomplished by performing data collection at some pre-determined interval (like once every 15 minutes).

(c) Unit-specific approach uses a dedicated data acquisition module with processor and memory that is dedicated to a single unit being monitored. Local display of live readings is desirable but not required. Each unit may be connected by communication devices to a centralized server for continuous monitoring, analyzing, and data storage at a single location.

(d) Centralized approach uses a centrally located data acquisition module with processor and memory that is connected to all the units being monitored. These may be connected directly or by means of a communication device to a server for continuous monitoring, analyzing, and data storage at a single location.

(e) Additional modules may be required to accept analog inputs from existing devices with ability to capture slow varying signals, possibly via SCADA or directly from other data collection sources.

(f) Monitoring hardware details should include the following minimum features: desired number of input channels; compatibility with several types of analog input; ability to synchronize all inputs; detailed alarm capabilities; receive external signals; sampling rate per channel; communication protocol; data display; real-time raw analog signal output; processed data output; and alarm signal output(s).

(3) *Computers/Servers/Communication*.

(a) Locate servers inside of physically controlled and secure space accessible only to authorized personnel.

1. This approach, along with USACE personnel performing routine data monitoring and software maintenance, is the most robust and secure approach, as compared to exporting data to an external entity for monitoring and maintenance. Desktop computer(s) for viewing the data may be located outside the physical perimeter only if the computer(s) have access privileges limited to viewing and analyzing data, live and stored. Desktop computer(s) for viewing should have access privileges limited to allow only authorized personnel to make changes to the configuration of system settings related to alarm and trip levels.

2. Alternately, changes to the configuration of system settings could be limited to authorized access at the server. Access to stored data on the server may also be accomplished by laptop computer with the same viewing restrictions as described for the desktop computer.

(b) The server, desktop computer(s), laptop computer(s), and network switches should be provided with all compatible software installed and licensed, with software and license keys provided on separate media. If network switches are used, they should be managed switches. Communication protocols should be compatible with the existing system to be connected to. Network devices should have cybersecurity controls applied according to applicable DoD and Army standards. The cybersecurity specification section should be included with contract solicitations.

(c) Hardware specifications should describe the desired processor speed and memory capacity that are compatible with the software requirements, and potential upgrades thereof. Hardware description should also specify the required power supply, cabling ports protocol, and the desired medium for data storage, commonly available at the time of purchase. Ports and adapter features should be limited in compliance with cybersecurity protective measures per UCIC standards.

(4) *Monitors/Displays*.

(a) Quantity and location of displays need to be determined by PDT as this relates to implementation specific to the site.

(b) Hardware specifications should describe the desired size, video signal and performance, power supply, and cabling ports protocol that are compatible with the computer/server to which it will be connected.

(5) *Communication*. For connections and communication within the system as well as for those involving other systems, follow guidance provided in Chapter 34.

28–5. Installation

The installation may be accomplished by either the Contractor or the project personnel. Either approach is acceptable but requires specific adjustments to this scope. There are benefits and costs associated with both, such that an evaluation should be used to determine which method is applied at the given location.

28–6. Design

a. Design submittals for MCM systems are of a performance nature for USACE, regardless of contract type. Most of the system scope is to be supplied with commercially available components. The integration with other site-specific systems may require new design effort.

b. Designs for the new systems typically use existing facility cable trays and routing in combination with new supplied wiring, cables, and commercially available equipment.

28–7. Drawings

a. Design concept drawings or diagrams of the data collection and communication architecture are required for UCIC approval, starting as early as possible in the design stages, because collecting data and communicating data within the powerhouse comes with cybersecurity requirements.

b. Detailed, final design drawings or diagrams are required to show proper implementation of previously approved design concept and need to be resubmitted to UCIC. These drawings should be Contractor prepared when the Contractor performs installations. This same requirement for detailed, final design drawings or diagrams should be the responsibility of the project personnel when the project personnel perform the installation.

28–8. Control Room

a. Duplication of live data display may be provided to the operator in the control room. The PDT should make this determination based on how units are operated. For example, some turbine/pump units may require close monitoring of live data during the stop/start sequence to minimize the effects of vibration by adjusting operational parameters.

b. Control room operators do not need to have the ability to change configuration settings related to alarm and trip settings.

28–9. Standards and Action Levels

a. Set points may be for annunciation, alarm, or request for maintenance intervention or inspection. On notification of reaching a set point for alarm or trip, the data should first be reviewed by a trained person (such as a control room operator, maintenance staff, or engineer) with access, before proceeding with action to shut down a unit. At the time of publishing, there is no widely accepted industry standard for setting trip levels to automatically shut down a unit.

b. Establishing mechanical alignment, balancing, rotor circularity and concentricity, and stator circularity and concentricity tolerances should consider the following references.

(1) USBR FIST 2-1.
(2) IEEE Standard 492.
(3) HPLIG CEATI Report Number T052700-0329.

c. Establishing mechanical dynamic tolerances and limits should consider the following references for guidance in determining set points for action.

(1) ISO 10816-1:2014.
(2) ISO 10816-3:2014
(3) ISO 10816-7:2014
(4) ISO 7919-5:2005
(5) ISO 20816-5:2018.
(6) HPLIG CEATI report number T142700-0389.

d. The guidance in ISO 7919-5:2005 and ISO 20816-5:2018 should be used to establish the acceptance criteria, meaning the acceptable operating limits based on vibration data. Shaft displacement alarms should be set for normal purposes following the ISO guidance and peak-to-peak sustained displacement at no more than 75 percent of bearing clearance. As described in the ISO guidance, “sustained” vibration refers to the mean value over 10 rotations of the shaft. If the software allows, considerations could take into account implementation of alarm setpoints based on a percentage increase compared to normal operating levels or baseline.

(1) During protective monitoring, the system should help to prevent or minimize machine damage. Based on guidance in ISO 7919-5:2005, the recommended alarm value for vertical shaft turbine guide bearings is 18 mils peak to peak sustained for generating units operating between 60 to 100 rpm and producing 85 MW and larger. Consideration should be made to determine if this alarm value is appropriate for implementation based on the OEM designed bearing clearances. Additional comparisons should consider the new values provided based on more defined machine structures displayed in ISO 20816-5:2018, tables A.1 through A.4. For operating conditions, such as field flash and breaker closure, which are not sustained for a significant duration, it is not necessary to alarm but values should be noted and trended.

(2) Operation in turbine rough zone(s) is likely to last much longer than 10 rotations of the shaft, thereby producing sustained higher vibration peak values. The vibration peak values are usually not high enough to alarm but values should be noted and trended. If peak values do exceed the alarm level, appropriate measures should be taken to improve conditions or minimize length of time in the rough zone.

(3) When and where additional information is available from shaft vibration testing or trended data and/or measured bearing clearances, it is possible to adjust the recommended alarm value either up or down after all the variables are examined by a qualified person. Qualified is defined as a trained vibration specialist. Setting trip values should consider all the same variables and be given additional considerations for human review before taking action.

28–10. Connecting to Existing Alarm Panels

The designer should consider connecting analog or other types of output signal from the MCM system to existing alarm panels or annunciation boards.

28–11. Training

a. Project staff should be trained for operating the equipment, including the communication switches, and for analyzing the data. The supplier should provide the operational training directly on installation and commissioning of the first unit. The training for data analysis and trending is typically delayed by 6 months to give personnel an opportunity to become familiar with the equipment. A third training is also recommended to review approximately one year’s worth of data and seek to understand any data trends.

b. The training should include the supply of manuals and a digital copy of the presentations used in class. All training sessions should cover the procedures for applying software and firmware updates for the devices supplied.

28–12. Reporting

a. The Project engineer, if available, should be trained to review data periodically and report all findings to their supervisor. This kind of reporting should be used to inform decisions regarding maintenance procedures and possibly capital project expenditures.

b. A wide range of vendor expert services are available and may be contracted to review sets of data and provide a comprehensive condition assessment on a single unit or on all units within a given powerhouse. This kind of reporting should be used to inform decisions regarding maintenance procedures and possibly capital project expenditures.

Chapter 29
Oil Spill Prevention

29–1. General

a. Hydroelectric generation facilities contain different types of oils and greases necessary for the safe operation of equipment and systems at the hydroelectric facility. Hydroelectric generating facilities are, by necessity, located where spills can enter the water environment. All new and retrofit work performed at hydroelectric facilities should include oil spill prevention.

b. There are numerous statutes, regulations, and industry standards that may apply (all or in part), depending on the site and the equipment and systems involved in the specific hydroelectric work. *Site specific evaluation by persons knowledgeable in this type of environmental compliance is recommended*.

c. There are multiple engineered approaches to oil spill prevention that should be considered, as applicable.

(1) *Equipment Design*. Oil spill prevention should be considered in the design of all equipment and systems, such as by requiring redundant and/or high-performing seals, minimizing failure points, reducing the volume of oil needed, or reducing maintenance requirements.

(2) *Removal*. Removing the need for oil or grease in systems and equipment should be considered where practicable, particularly when in direct contact with the water environment.

(3) *Environmentally Acceptable Lubricants*. EALs should be considered for equipment in direct contact with the water environment requiring oil or grease or wire rope lubricant for safe reliable operation.

(4) *Oil Accountability*. Oil accountability tracks the use of oil and grease, bringing attention to any discrepancies to minimize unseen losses. Designs should incorporate oil accountability, particularly for equipment and systems in direct contact with the water environment.

(5) *Containment*. Containment provides a secondary level of protection to capture and contain oil and oil-water mixtures before oil can reach the water environment.

(6) *Oil-Water Separation*. Oil-water separation systems remove oil from oil-water mixtures prior to release of the water. These systems may be required when containment is not feasible.

29–2. References and Resources

a. Clean Water Act (CWA) §311 40 CFR part 112.

b. ER 200-2-3.

c. EP 200-2-3.

d. UFC 3-600-01.

e. EPA 800-R-11-002.

f. EM 1110-2-1424.

g. NFPA 70.

h. NFPA 850.

i. IEEE 980.

j. IEEE 979.

29–3. Spill Prevention, Control and Countermeasure Plans

All USACE hydroelectric facilitates have spill prevention, control, and countermeasure (SPCC) plans according to CWA §311 40 CFR part 112. The SPCC deals mainly with a project's capability to prevent and detect spills, their preparedness for spill incidents, and their planned response to spill incidents.

a. SPCCs are useful references for identifying oil-filled equipment and systems, and specific engineering controls used to prevent oil discharge.

b. Work performed at hydroelectric facilities should consider existing SPCC plans and these plans may need to be updated as engineered approaches to oil spill prevention are implemented.

Chapter 30
Arc Flash and Coordination

30–1. General

a. Arc flash occurs when electric current jumps from one conductive surface to another through air, generating intense light and heat. Additionally, the sudden intense heat from the arc flash creates an explosive expansion of the surrounding air and metal in the arc path, known as an arc blast. An arc blast consists of high pressures, sound, and shrapnel. The combination of an arc flash and resultant arc blast can cause damage to equipment and serious injury or death if a person is not properly protected while working in or around exposed live electrical equipment. Identifying potential arc flash hazards around equipment and the proper personal protective equipment (PPE) to be used provides a safer work environment.

b. Arc flash studies are part of the electrical safety requirements per ER 385-1-100 and NFPA 70E. These studies should be updated at least every 5 years or when changes to equipment or protective device settings occur. The studies identify the potential incident energy available at the various electrical equipment at the plant. This data is used in the arc flash risk assessment that is required prior to any energized electrical work to identify the additional controls, procedures, and PPE that must be in place prior to the start of the live electrical work.

c. Coordination studies are recommended to provide the best possible tripping scheme for a facility to ensure system reliability. A properly coordinated system should remove from service only the equipment necessary to isolate the fault. In many cases, a well-coordinated system also offers the safest working conditions.

30–2. Arc Flash Study

Arc flash studies quantify the amount of thermal energy available at a piece of equipment by using either a table from the NFPA 70E or calculations defined in IEEE 1584. The table method from NFPA 70E should be used only as short-term solution in cases where system changes have occurred and an arc flash study has not yet been completed or updated. The detailed incident energy calculation method is required for USACE facilities by ER 385-1-100. The calculations combine short-circuit calculations, empirical equations, and protective device operating times to estimate incident energy (IE), arc flash boundary, and PPE requirements.

a. Data Collection. Site investigations are used to collect and verify data on equipment from 50V to 15 kV. Data can include, but is not limited to, device ratings, protective device settings, and equipment nameplates. This information is entered into the software model and used in the calculations. Typical equipment included, but not limited to, is switchgear, MCCs, panelboards, batteries, DC switchgear, disconnect switches, motors, transformers, cable lengths, cable types, fuses, and other protective devices.

b. Software. Power system analysis software is used to model the facilities. The facility is modeled using data collected in the field. Once the model is built, a hand calculation of the short-circuit current should be performed at a point in the system to verify the accuracy of the model and that the results from the software are as expected.

c. *Analysis*. Due to the multiple sources of power and different possible configurations for critical switchgear and MCCs at hydroelectric facilities, multiple operating configurations should be modeled to determine the worst-case incident energy levels.

d. *Label Requirements*. Labels are to follow the latest requirements of NFPA 70E. Typically, the name of the project, bus identifier, nominal voltage of the bus, arc flash boundary, working distance, and available incident energy or the minimum arc rating of clothing is listed on the label.

30–3. Coordination Study

a. The goal of a protective device coordination study is to assure that the system can clear a fault in the minimum amount of time possible, while also maintaining the maximum availability of the system. This reduces unnecessary downtime for equipment and increases the reliability of the facility. Coordination is most important at the main 480V switchgear, as the miscoordination between the main and feeder breakers could take multiple generator units out of service due to the loss of unit auxiliary equipment required for generator operation.

b. Time current curves (TCCs) identify the operating regions of the protective devices. Each protective device has a unique TCC. In a coordination study, the characteristic curves of the protective devices are analyzed by overlaying them against one another on log-log plots. Areas that are not properly coordinated are apparent by the overlapping of the operating regions of two or more devices. For devices with adjustable trip settings, the TCC can be adjusted to improve coordination.

c. For a properly coordinated system, the protective devices are set to trip in sequence with the breaker closest to the fault tripping first. If the breaker fails to operate to clear the fault, the next upstream device should trip to attempt to clear the fault, and so on. This increases facility reliability by limiting the effects of a disturbance (such as a fault or overload) to the smallest possible area of the distribution system. In general, the main protective device(s) at a switchboard or panelboard are compared against the largest feeder protective device. If coordination exists at this level, then coordination is assumed for all devices at the switchboard or panelboard in question.

d. Where the study identifies areas of miscoordination, alternatives for improving the coordination should be identified, if possible. In many cases, perfect selective coordination is not possible, and compromises will have to be made. In these cases, engineering judgement must be used to coordinate the devices as best as possible to minimize the impact of any system disturbance.

Chapter 31
Wire and Cable

31–1. General

This chapter focuses on wire and cable rated under 2,000 volts, and briefly covers medium-voltage cable. IEEE 422 provides overall guidance in planning, designing, and installing wire and cable systems in a power plant. Topics covered in the IEEE guide include cable performance, conductor sizing, cable segregation systems, installation and handling, acceptance testing, and other related subjects. Additional guidance is provided in EPRI EL-5036, Volume 4.

31–2. Evolution of Industry Standards

a. The ICEA has been merging their standards with the NEMA Wire and Cable (WC) standards such that any particular standard is likely to have two completely different standard numbers sharing the same title. To be all-inclusive, this chapter refers to these dual standards as ICEA #/NEMA WC #.

b. NEMA reorganized the structure of their WC standards rendering legacy references such as WC 5, WC 7, and WC 8 obsolete. These references should be verified and changed to the applicable references in the WC 50-series, WC 60-series, and WC-70 series.

c. The Association of Edison Illuminating Companies (AEIC) standards have evolved to simply refer to the applicable ICEA/NEMA WC standards for wire and cable used for general construction. Older specifications using just AEIC references should be updated to the latest ICEA/NEMA WC standards as applicable.

31–3. Cable Sizes

The minimum size of conductor for current-carrying capacity (ampacity) up to 2,000 volts should be based on the NEC, Table 310.15(B)(16) for 60 °C (140 °F) insulated wire up to No. 1 AWG, and 75 °C insulated wire sized No. 1/0 AWG and larger. This aligns with UL testing performed for commonly used terminal connections rated 60 °C (140 °F) and 75 °C (167 °F). Insulated wire rated 90 °C (194 °F) may then be used after sizing has been accomplished, if necessary to take advantage of the smaller cross-sectional diameters to fit inside existing raceways. Circuit voltage drop should be checked to ensure the total drop from the source to the equipment does not exceed the requirements of the Notes in Articles 210 and 215 of the NEC.

a. Ampacity Rating. Ampacity for cables over 2,000 volts up to 35,000 volts should be based on the tables in the NEC Article 310.60. Ampacities for higher voltages should be based on cable manufacturers' data for specific installations.

b. Cables in Cable Tray.

(1) Cables in cable tray must be multi-conductor for sizes No. 1 AWG and smaller, regardless of voltage rating. Cables in cable tray should also be limited to 1,250 kcmil maximum to facilitate flexing from thermal expansion and contraction. Larger sized cables behave more like solid bus and may flex enough with sufficient force to press against the tray sides or tray supports, thus risking damage to the cable tray or to the cable jackets and insulation.

(2) Tray cables should be “tray-rated” or indicated as TC to verify having passed the more stringent requirements for vertical tray flame testing such as IEEE 1202, (previously IEEE 383), Canadian Standards Association (CSA) C22.2 No. 0.3-01, or UL 1685. Metal-sheathed cables such as type MC or mineral insulated (MI) may also be run in cable tray if they have passed these vertical flame tests. Non-metal sheathed cables smaller than No. 1/0 AWG in cable tray must be run as part of a multi-conductor tray-rated cable per the NEC.

31–4. Functional Categories

Wire and cable for power, controls, and feeders fall into functional categories according to their purpose. The most common functional categories recognized for powerhouses include the following:

a. *Lighting*. 600-volt rated single conductor or multiconductor, usually No. 12 AWG to No. 8 AWG (may go up to 500 kcmil), operated at 120/240VAC 1-phase or 208Y/120VAC 3-phase. Used for lighting and receptacle branch circuits or small feeders to mechanical equipment, although still considered as a “lighting” load because of the voltage.

b. *Power*. 600-volt rated single conductor or multiconductor, No. 12 AWG to 1000 kcmil, operated at 480VAC 3-phase. Used for station service distribution such as feeders to panelboards and mechanical equipment, or branch circuits to welding receptacles. May include 125VDC or 250VDC for generator field flashing.

(1) Main unit feeders and some station service feeders may require medium-voltage cable, rated for either 5 kV for 4,160-volt systems or 15 kV for 13,800-volt systems. For systems that are either ungrounded or are resistance or reactance grounded, a ground fault may be carried for over one minute, thus requiring an insulation level of 133 percent, or 33 percent thicker than the nominal 100 percent thickness. Cables with the minimum 100 percent insulation level are suitable only for solidly grounded systems that trip immediately on any ground fault. Cables for these voltages are either MV-90 (most have a cross-linked insulation and are suitable for a maximum conductor operating temperature of 90 °C [194 °F]) or MV-105 (most have an EPR-based insulation and are suitable for a maximum conductor operating temperature of 105 °C [221 °F]). Tree-resistant cross-linked (TR-XLP) cables are also available as type MV-105.

(2) Some plants have station service generators operating at 2.4 kV. Although lower voltage ratings are available in unshielded medium-voltage cable, hydroelectric powerhouse practice is to use nothing less than 5 kV shielded cable. Some plants have main units generating at 6.9 kV, in which case 8 kV rated cable is required. Dual-rated 5/8 kV cable is not recommended because the cable may be rated for 133 percent insulation only at 5 kV, and just 100 percent at 8 kV.

c. *Control*. 600-volt rated, unshielded multiconductor, No. 14 AWG to No. 10 AWG, operated at 125VDC or 120VAC. Used between control switchboards and generators or switchyards for metering and relaying and for equipment operation (breaker or switch open/close, unit start/stop). Metering and relaying applications should use No. 12 AWG minimum for voltage transformers and No. 10 AWG minimum for CTs. For internal PLC cabinet wiring, use of No. 18 AWG control wiring is permissible. Most

I/O module terminal blocks cannot accommodate any size larger than No. 16 AWG conductors.

(1) Type SIS (switchboard wire) should be used inside of switchboards and enclosures for internal interconnections because of its finer stranding and more robust insulation as opposed to the more common forms of rubber or cross-linked types, such as RHW (rubber, heat-resistant, water-resistant) or XHHW (cross-linked polyethylene, high heat-resistant water-resistant). However, Type SIS is not tray-rated and should not run externally for connection to controlled equipment. See NEC Table 310.104(A), Conductor Applications and Insulations Rated 600 Volts for type definitions and descriptions.

(2) Type SIS No. 12 AWG is actually 19 strands of No. 25 AWG wires. Type SIS No. 10 AWG is actually 19 strands of No. 22 AWG wires. These were traditionally referred to as sizes No. 19/25 AWG and 19/22 AWG respectively, but that nomenclature is no longer popular across the industry. The specifications should indicate the desired stranding for various purposes as well as where Type SIS wire is required.

d. Annunciation and Instrumentation. 600-volt rated, No. 14 AWG (No. 16 AWG maximum for PLC connections), unshielded twisted pairs (UTP), or multiconductor cables. Usually operated at 125VDC to monitor system status and to alert the powerhouse operators to abnormalities. May sometimes overlap with communications/data functions for 4-20 mA signals, RS-232, RS-485, and SCADA. A more specialized form of SCADA that is used in many USACE powerhouses is generic data acquisition and control system (GDACS).

(1) Shielded twisted pairs (STP) are used for analog signals or those operating at less than 24 volts. They are also used for PT circuits for digital governor installations as they rely on clean voltage signals for the frequency reference.

(2) Most RTD leads are shielded 300-volt rated and may be as small as No. 20 AWG. This is acceptable, but connecting cables must also be shielded and the shields connected but grounded at one end only. The leads and any 300-volt rated connecting cable should be run in a separate raceway than for 600-volt rated cables or conductors.

e. Communications/Data. 600-volt rated (300-volt for Ethernet cable) unshielded pairs, multiple pairs, or multiconductor, No. 24 AWG to No. 20 AWG, usually operated at 24 volts (or less) AC or DC. Often designated as Type CM for general use, CMR for riser-rated, CMX for outdoor/direct burial rated, or CMP for plenum rated (preferred) and applied mostly according to the NFPA 70, NEC Chapter 8, articles on communications circuits. Used for Ethernet (Category 6 preferred), local area network (LAN) and telephone, using UTPs. Also may be used for RS-232, RS-485, Modbus, SCADA, or GDACS. Ethernet cable is not typically available with a rating over 300 volts and may require a separate raceway.

(1) Shielding for communications/data cable should be required only for analog signals, signals operating at less than 24 volts, or as otherwise recommended by the equipment manufacturer.

(2) Communications/data cables may also be fiber optic. For distances over 3,000 ft (914 m), single-mode cable (8.3 to 10 microns) may be required. For most powerhouse applications, the more versatile multi-mode cable (50–62.5 microns) is suitable; however, multi-mode cable should be a graded index type to preserve signal quality. Fiber optic cables that are run with other types of wire or cable in large ducts or

cable tray should be run inside an innerduct for physical protection and easy identification.

31–5. Insulation Materials

Insulation protects the bare conductor from short-circuiting to other conductors in the circuits and to objects that are at a different potential (including grounded objects) but are within range of touching or flashing over. The two families of materials for most wire and cable insulation and jackets are thermosets and thermoplastics. Table 310.104(A) of the NEC provides the definitions for the 2- to 4-letter codes used to identify the properties of the many insulation types for 600-volt rated conductors. Medium-voltage cables are more generally categorized as EPR or cross-linked polymers (XLP) and suitable for conductor operating temperatures of 105 °C (221 °F) or 90 °C (194 °F).

a. Thermoset Insulation. Thermoset materials have less tendency to melt during a fire than thermoplastics. Thermosets also have greater resistance to abrasion and ozone deterioration and tend to have a longer useful life than other types of insulation. Most thermosets use rubber as a major component and are generally categorized as an EPR material. For 600-volt rated conductors, EPR materials are suitable for 75 °C (167 °F) or 90 °C (194 °F) operation depending on the specific type of material. The most common rubber insulations for 600-volt wiring are RHH (rubber, high-heat resistant) and RHW (rubber, heat-resistant, water-resistant). Type SIS as described above for switchboard wiring is also a thermoset.

b. Thermoplastic Insulation. The most common polymer insulations for 600-volt wiring are THHN (thermoplastic, high-heat-resistant, nylon coated) or THW (thermoplastic, heat-resistant, water resistant). Thermoplastic materials are polymers that tend to sag over time and thus decrease in thickness at bends, which can lead to flashover conditions. Thermoplastics also tend to melt away from the conductor during a fire. Thermoplastics are less expensive than thermosets or cross-linked polymers and are the default insulation submitted if the wire and cable specifications are not stringent. Thermoplastics are not recommended for powerhouse wiring.

c. Cross-Linked Polymers. Cross-linked polymers are thermoplastic polymers that have been treated to make them behave more like thermoset materials, except for the longer expected useful life of true thermoset materials. This cross-linking process also makes them more expensive than regular polymers but typically still less expensive than EPR thermoset insulations. Cross-linked materials are generally categorized as an XLP (cross-linked polymer), or often more specifically as XLPE for cross-linked polyethylene. Operating temperatures for 600-volt XLP wiring are the same as for 600-volt EPR, depending on the types of materials. The most common cross-linked polymer insulations for 600-volt wiring is XHHW.

d. Insulation Material Exceptions. Exceptions are permitted. Some thermoplastic insulations are suitable for their intended use or may be accepted due to current market conditions affecting price and/or availability. Where such insulation types are required or are an expected probability, they may be listed in the specifications as an exception but only for the specific application described.

(1) Polyvinyl chloride (PVC) is typically prohibited due to the outgassing of poisonous chlorine vapor when it burns, although the hazard presented by small quantities is debatable. Unfortunately, PVC is the most commonly available insulation

for wire and cable sized No. 20 AWG and smaller, including No. 24 AWG Ethernet cable and fiber optic cable. Insulation-type FEP (fluorinated ethylene propylene) is an acceptable and usually available alternative to PVC insulation for Ethernet and fiber optic cable.

(2) Machine tool wiring (MTW) has a thermoplastic insulation that is actually PVC. However, it is formulated for hot, moist, and greasy environments and is the manufacturer's standard for most motor control center cubicle wiring, crane controls, governor controls, and other factory-assembled control enclosures. The relatively small amount of PVC in these installations does not pose a life-threatening hazard. However, it should be limited to internal enclosure wiring and not extended outside the enclosure for external wiring.

(3) Cross-linked polyolefin (XLPO) is similar to XLPE in that it is a thermoplastic material that has been cross-linked during manufacturing. XLPO is relatively new to the industry for general construction and has yet to be included under the XLP umbrella used by the ICEA/NEMA WC standards that currently only stipulate XLPE. However, XLPO is built to identical parameters as XLPE and is an acceptable substitute for XLPE.

(4) FEP is a fire-retardant material often used for plenum-rated (CMP) cable. This is a commonly used alternative where installation requires smaller-sized cables typically available only with PVC insulation. It may also be known by its proprietary name, Teflon.

(5) Low smoke zero halogen (LSZH) has recently become industry's response to the prohibition of PVC. It is typically a thermoplastic formulated to reduce the amount of smoke created by burning insulation and to eliminate harmful outgassing. Like FEP, it is a commonly used alternative where installation requires smaller-sized cables typically available only with PVC insulation.

(6) MI cable is actually a thin metal tube around the conductor, filled with magnesium oxide for very hot environments. Some powerhouses used MI cable in the turbine pits because solid dielectric insulations were not yet robust enough for that environment. Modern solid dielectric materials have improved greatly over the years and may now safely face the turbine pit environment. Type MI cable is very difficult to install properly, and the expertise to do so is being lost within the industry. A suitable replacement is MC cable, using XHHW-2 insulation rated for 90 °C (194 °F).

31–6. Jacket Materials

Jackets are coverings over the insulation to protect it from damage during installation or from environmental factors over time. Jacket materials are similar to insulation materials in that they can be thermosets, thermoplastics, or cross-linked polymers. When jackets are required, they are typically a different material than that used for the insulation. As with insulation, thermosets are preferred but thermoplastics may be accepted for certain applications based on availability. The heavy duty (HD) suffix used to be a requirement for any jacket material, but in recent years these have become special orders having excessive costs and lead times.

a. Neoprene (CR) is a synthetic rubber and is preferred.

b. Chlorosulfonated polyethylene (CSPE) is a proprietary thermoplastic formulation no longer produced, but variations are still available from manufacturers.

c. Cross-linked chlorinated polyethylene (XL-CPE) is a thermoset, also available as CPE, which is a thermoplastic. CPE may be accepted as a variance based on availability of XL-CPE. But do not confuse this with polyethylene (PE) or high-density polyethylene (HDPE)

d. XLPO is also used for jackets. XLPO is gaining in popularity and is typically offered as a variance to CR, CSPE, and XL-CPE jackets, based on availability.

e. FEP is also used for jackets and may be offered as a variance, based on availability.

f. LSZH is also used for jackets and may be offered as a variance, based on availability.

g. Exceptions are permitted for PVC jackets on MC cables of any size, and liquid-tight flexible conduit connections to equipment subject to vibration (3 ft [.9 m] length limit) simply because the industry does not offer any alternative materials. PVC jackets may also be accepted for similar reasons on No. 20 AWG and smaller cables; however, Ethernet cable is commonly available with an optional LSZH jacket, even though the insulation material may be PVC. This also applies to fiber optic cable.

31–7. Field Acceptance Testing

Although ICEA/NEMA WC and IEEE standards offer direction on wire and cable testing, the commonly accepted standard for tests to be performed, recommended test parameters, and acceptable results is the International Electrical Testing Association (NETA) standard ANSI/NETA ATS, Acceptance Testing Specifications for Electrical Power Distribution Equipment and Systems.

a. Conductor continuity tests should be the first tests performed on all installed wiring to verify there are no breaks in the circuit.

b. The insulation resistance test should be performed on all wire and cable, regardless of voltage rating. This test is commonly referred to as a “Megger” test; however, Megger is a proprietary name for test equipment and should not be used in specifications.

c. The high-voltage, or high-potential test should also be performed on all cables rated 5,000 volts and higher. This test is commonly referred to as a “hi-pot” test. This test traditionally used only DC voltages, which required small inexpensive equipment. In recent years, cable manufacturers have insisted on using only AC voltages for high-potential testing, which requires more sophisticated equipment. Studies have found that DC high-potential testing can accelerate aging in newly installed cases and may even void the warranty on medium-voltage and high-voltage cables. AC testing at 60 Hz has also become somewhat controversial, leading to increased popularity of low-frequency, AC, high-potential testing.

d. Shield continuity tests should be performed on all shielded cable, whether low-voltage instrumentation or medium-voltage power cable.

31–8. Maintenance and Condition Assessment Testing

There are no firm standards recommending recurring electrical testing. Diagnostic electrical tests for maintenance and planning purposes may be performed at any time, except that repeated testing at voltages higher than service voltage accelerates the aging of any wire or cable.

a. Visual inspections should be performed on all critical wire and cable annually to look for cracks or penetrations in jackets and/or insulation.

b. Although NETA Maintenance Testing Specifications (MTS) recommended test voltages for older cable assessment are the same as for NETA ATS recommended test voltages for new cable acceptance testing, the cable industry typically recommends performing the above tests at half of the recommended acceptance test values for condition assessment if several years have passed since installation; however, there is no industry consensus as to how many years this interval should be. Insulation resistance testing at half voltage is deemed safe on very old cables of all voltage ratings if condition assessment is necessary. High-potential testing of medium-voltage or high-voltage cables should be done only if there is reason to suspect damage that could lead to failure and flashover.

c. Step voltage testing for feeders at any voltage may be performed if there is need to decide whether the feeder must be replaced or may remain in service. There is no standard governing this test; however, industry consensus for a pass/fail condition assessment of cables that have been in service for 30 to 40 years is to perform a one-minute insulation resistance test of each conductor with both ends disconnected at 500VDC. After the cable has discharged, the test is repeated at 1,000VDC for 600-volt rated cables, or at 2,500VDC for cables rated 5kV or higher. Record the leakage current for each conductor, and the insulation resistance of each conductor. If any single conductor of the feeder fails the test criteria, or if the conductors as a group are not within the tolerances listed below, all three conductors of the feeder should be replaced. An individual conductor should be considered a failure if:

(1) The insulation resistance is less than two megohms at either test voltage; or

(2) The leakage current rises and fails to stabilize during the one-minute test at either test voltage.

(3) If all three conductors pass the above criteria, compare the results. The feeder should be considered a failure if the insulation resistance between any of the three cables differs by more than 25 percent of the lowest resistance at either test voltage.

31–9. Conduit, Cable, and Equipment Designations

Generally, each circuit or feeder between major units of equipment or from major units of equipment in the powerhouse to structures external to the powerhouse is assigned a designation. Conduit and cable should have the same designation, if possible. The designation should give information about the service rendered by the circuit or feeder, the termination points, and the voltage or power classification according to Table 31–1. The designation is made up of three parts, as follows:

a. The first part of the designation identifies the equipment at the source of each circuit or feeder and is composed of uppercase letters and numerals assembled into a code to represent the various major units of equipment, switchgear, switchboards, cabinets, etc., located throughout the powerhouse.

b. The second part of the designation is composed of a lowercase letter and numeral. The letter indicates the type of service rendered by circuit or feeder (power, alarm, etc.) or its operating voltage, while the number differentiates between like circuits or feeders running between the same two points (source and destination).

c. The third part of the designation identifies the equipment at the destination of each cable run and is composed in the same manner as the first part of the designation.

d. Example: SC-u3-G1.

SC = start of circuit (main control switchboard)

U = type of service (annunciator lead)

3 = number of such cable (3rd annunciator lead cable to generator No. 1)

G1 = termination of cable (generator No. 1)

e. Designations for general-purpose circuits or feeders between low-voltage equipment (such as motor control centers) and minor units of equipment (such as welding outlets) may have no code letter and numeral to show the termination of the run. The designation in these cases are made of only the first two parts. The first part indicates the start of the cable run, while the second part indicates the type of service rendered by the cable.

f. Example: CQ5-q3.

CQ5 = start of feeder (480-V load center No. 5)

Q = type of service (480V power)

3 = circuit number (third general purpose feeder from this source)

Table 31–1
Conduit, cable, and equipment designation letters

Terminal Equipment (first designator for source, or third designator for destination)	
Operator’s Desk, Switchboards, and Switchgear (add No. if more than one, such as SB2)	
SA	Fishwater Generator Switchboard
SAT	Satellite Digital Processor
S	Generator Switchboard (usually followed by panel number, see notes in paragraph 31–9g)
SB	Battery Switchboard
SC	Main Control Switchboard
SCC	Main Control Console
SG	Graphic Instrument Switchboard
SL	Load Control Switchboard
SO	Station Service Switchboard
SOC	System Operations Controller
SJ	13.8 kV Switchgear
SP	4,160V or 2,400V Switchgear
SQ	480V Switchgear
SH	Heating Switchgear
ST	Status Board
SU	Main Unit Auxiliaries Motor Control Center

Terminal Equipment (first designator for source, or third designator for destination)	
SR	Lighting Switchgear
SX	Excitation System Equipment (Add No.)
GN	Generator Neutral
OD	Operator’s Desk
CC	Carrier Current Equipment
ER	Electrical Equipment Room Cabinets
MUX	Multiplexer
MW	Microwave Terminals
FSC	Fishway Switchboard
DOC	Digital Operations Controller
ROC	Remote Operations Controller
FSP	4,160V Fishway Switchgear
FCP	4,160V Fishway Controller
FSQ	480V Fishway Switchgear
FSU	Fishway Unit Switchgear
TF	Telephone Frame
Load Centers	
CP	4,160V or 2,400V Load Center
CQ	480V Load Center or Motor Control Center in Powerhouse
CR	120/240V or 120/208V Panelboard
CD	48V DC Panelboard
CE	125VDC Panelboard
CF	250VDC Panelboard
CA	Emergency Lighting
CH	Preferred AC Panelboard
CY	CO_2 Cabinet
DQ	480V Load Center or Motor Control Center in Dam (spillway or intake structure)
FCP	4,160V or 2,400V Load Center in Fishway or Fish Facility
FCQ	480V Load Center or Motor Control Center in Fishway or Fish Facility
PQ	480V (project)
Apparatus	
A	Actuator or Governor (add Unit No.)
B	Battery (add voltage letter, then add number if more than one)
SX	Exciter (add Unit No.)

Terminal Equipment (first designator for source, or third designator for destination)	
G	Generator (add Unit No.; also U for Unit)
GF	Fishwater Generator (also UF for Fishwater Unit)
X	Breaker (add voltage letter)
T	Transformer (power, not instrumentation or control)
Z	Disconnecting Switch (add voltage letter)
CT	Current Transformer (separate unit, such as switchyard – add voltage letter)
VT	Potential Transformer (separate unit, such as switchyard – add voltage letter)
LA	Lightning or Surge Arrester (separate unit, such as switchyard – add voltage letter)
EG	Engine Generator
MG	Motor-Generator
MC	Motor Control Cabinet (for control only, no breakers)
M	Motor
K	Crane
FT	Fishway Transformer
Miscellaneous Terminal Equipment, Boxes, or Structures (Some items in this list are used for cable and conduit terminals, but a majority are used only as modifying suffixes for devices on schematic diagrams)	
AA	Governor Air Compressor
AH	Air Horn
AN	Annunciator
AQ	Governor Oil Pump
AR	Annunciator Reset
AS	Ammeter Switch
BC	Battery Charger
BG	Break Glass Station
BK	Brakes
BU	Bubbler System
BV	Bypass Valve or Butterfly Valve
CAC	Central Air Conditioner
CJB	Junction Box, Master Control Circuits (modify by Unit No.)
CM	Channel Manometer
CPD	Capacitance Potential Device
CPT	Control Power Transformer
CTC	Control Terminal Cabinet
DP	Drainage Pump

Terminal Equipment (first designator for source, or third designator for destination)	
DS	Deck Station
DT	Differential Transmitter (transducer)
DWP	Domestic Water Pump
EA	Sewage Aerator
EC	Effluent Comminutor
EF	Exhaust Fan
EH	Electric Heater
EHQ	Electric Oil Heater
EL	Elevator
EP	Sewage (effluent) Pump
ETM	Elapsed Time Meter
EV	Electrically Operated Valve
FM	Flow Meter
FP	Fire Pump
FS	Float Switch (device 71 preferred)
FTC	Fishway Terminal Cabinet
FW	Float Well
FWG	Forebay Water Level Gauge
GH	Generator Heater
GI	Ground Insert
GP	Grease Pump
GW	Generator Cooling Water (pump or valve)
HC	Head Cover Sump Pump
HD	Air Conditioning Damper
HF	Air Conditioning Air Filtration Equipment
HH	Air Conditioning System Humidifier
HP	High-Pressure Thrust Bearing Oil Pump
HQ	Conditioning System Oil Pump
HR	Air Conditioning System Refrigeration Pump
HV	Air Conditioning System, Master Devices
HW	Air Conditioning System Water Pump
HY	Hypochlorinator
IG	Intake Gate
IM	Intake Manometer

Terminal Equipment (first designator for source, or third designator for destination)	
IS	Intruder Detector System
IQ	Intake Gate Oil Pump
IV	Inverter
JB	Junction Box
LC	Load Control Cabinet
LT	Outside Lighting (480V)
LTH	High Bay Lighting
LTU	Line Tuning Unit
MO	Load Control Master
MOD	Motor Operated Disconnect
OR	Operations Recorder
OS	Load Control Station Operation Selector
PA	Station (plant) Air Compressor
PB	Pull Box or Pushbutton
PC	Program Controller
PG	Penstock Gate
PH	Powerhouse (add no. if more than one)
PR	Project Building
PS	Potential Selector or Pressure Switch (Device 63 preferred for pressure switch)
PT	Pressure Tank
PV	Penstock Valve
QPD	Oil Transfer Pump (dirty)
QPL	Oil Transfer Pump (lube)
QPT	Oil Transfer Pump (transil)
RC	Code Call Relay Box
RF	Recirculating Fan
RW	Raw Water Pump
SD	Servo or Shaft Oil Catcher Drain Pump
SF	Supply Fan
SN	Stop Nut
SO	Load Control System Selector
TA	Transformer Cooling Equipment Air System
TB	Telephone Box or Test Block
TBA	Turbine Bearing Oil Pump – AC

Terminal Equipment (first designator for source, or third designator for destination)	
TBD	Turbine Bearing Oil Pump – DC
TC	Terminal Cabinet
TD	Transformer Deluge
TE	Thermostat (heating and ventilation equipment drawings)
TH	Preferred AC Transformer
TM	Tailrace Manometer
TP	Turbine Pit
TQ	Transformer Cooling Equipment Oil Pump
TS	Test Station
TWG	Tailwater Level Gauge
UAC	Unit Air Conditioner
ULC	Unit Load Control Selector
US	Unit Selector
UV	Unloader Valve
UW	Unwatering Pump
VQ	Valve Oil Pump
XA	Circuit Breaker Air Compressor
XF	Circuit Breaker Cooling Fan
VS	Voltmeter Switch
WG	Water Gate (sluice, weir, etc.)
WH	Water Heater (hot water tank or boiler)
WP	Gate Wash Pump – Deck Wash Pump
WV	Water Valve
Modifying Terms for Individual or Separately Mounted Equipment (first or third designators)	
Suffix letters to further identify voltage class:	
U	500 kV (such as ZU for 500 kV disconnect switch)
M	230 kV (such as XM for 230 kV breaker)
W	115 kV (such as XW for 115 kV breaker)
J	13.8 kV or 7.2 kV (such as XJ for a 13.8 kV breaker)
P	4,160V or 2,400V
Q	480V
R	120/240V or 120/208V
F	250VDC
E	125VDC

Terminal Equipment (first designator for source, or third designator for destination)	
D	48VDC
H	120V Preferred AC
Suffix letters to further identify function:	
O	Station Service (such as TO for station transformer)
N	(as GN1, TN1) – Neutral
Y	CO_2 (such as CY for CO_2 cabinet)
Service Classification (second or middle identifier)	
a	Current Transformer – Shunt Leads
c	Control Circuits (unit controls including breakers, exciters, governors)
d	0 – 48VDC
e	Power Circuit, 125VDC
f	Power Circuit, 250VDC
fo/MM	Fiber Optic Muti-Mode
fo/SM	Fiber Optic Single-Mode
h	120V Preferred AC
j	Power Circuit, 13.8 kV AC
m	Power Circuit, 230 kV AC
p	Power Circuit, 4,160V or 2,400VAC
q	Power Circuit 480VAC
r	Lighting (power) Circuit 120/240V or 120/208VAC
s	Spare Conduits, Wires, or Cables
tr	Radio Circuits
t	Telephone Circuits, Intercommunication Circuits
ts	Sound Power Circuit
u	Alarm or Annunciator Circuits
uc	Code Call Circuits
ut	Carrier or Pilot Wire Circuit
v	Voltage (potential) Transformer Secondaries

g. Notes for applying Table 31–1.

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

(2) There are cases where a circuit runs through multiple conduits that are separated by cable tray or that pass through an enclosure or pullbox. The circuit retains the original designation throughout, but the conduit components should have numbered designations. For instance, a 480V feeder CQ1-q1 running through an undesignated pullbox should have the first conduit component to the pullbox designated CQ1-q1.1, and the second conduit component leaving the pullbox designated CQ1-q1.2.

(3) Instrument transformers and disconnecting switches mounted on a circuit breaker or circuit breaker structure have the cable and conduit designations of the breaker. For example, bushing-type CTs and potential devices mounted on circuit breaker XJ3 having circuits to control switchboard S3 should have cable and conduit designations XJ3-a1-S3 and XJ3-v1-S3, respectively.

(4) Equipment designations are used to designate major assemblies such as a switchgear assembly and not an individual breaker within the switchgear. Individual breaker designation is desirable but including it in the terminal designation (first term of cable code) complicates the system, impairing its usefulness. Thus, instrument transformers, breakers, and disconnecting switches mounted in a switchgear or switchboard take the terminal designation of the switchgear or switchboard.

(a) For example, a breaker mounted in a 480v switchboard has a feeder or control circuit designation of SQ for the first term. Even though the breaker inside the switchboard may have a number such as XQ1, this number is disregarded in the first term of the feeder or control circuit designation.

(b) Feeders to destination equipment XXX are designated SQ1-q1-XXX and control circuits SQ1-c1-XXX.

(5) When a switchboard has many breakers for circuits to miscellaneous apparatus, the second designator of the cable code is numbered to correspond with the breaker number. For example, CQ2-q8 and CQ2-q25 are 480V power circuits connected to breakers No. 8 and No. 25, respectively, in 480V panelboard No. 2. The number in the second designator differentiates one circuit from another and does not indicate the total number of conductors in that circuit.

(6) Wiring diagrams for a large switchboard or switchgear assembly (usually S, SJ, SP, or SU) may be spread across several drawings, which can lead to confusion. To avoid this problem, each switchboard or switchgear assembly may have its front panels numbered in order from left to right. The source equipment designation is the switchboard designation followed by the panel number, and the cable number then designates the panel at which it terminates. For example, on generator switchboard No. 1, the third panel from the left is designated S13 and a control circuit running from this panel to equipment XXX is designated S13-c1-XXX.

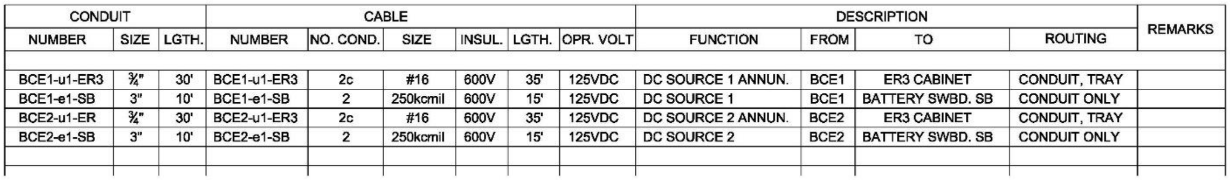
(7) In duplex switchboards having devices mounted in the front and back, a rear panel is designated by the letter “R” followed by a number corresponding to its front panel. For example, on Generator Switchboard No. 1, the third rear panel from the right is designated S1R3 and a control circuit running from this panel to equipment XXX has the designation S1R3-c1-XXX.

(8) Some vertical sections of a motor control center assembly may include two or more lighting panels designated CR or CA. The lighting panel designation is used for circuit designations for circuits running from these lighting panels in lieu of the vertical section number of the motor control center.

(9) Branch circuits from lighting panelboards are numbered to match the pole position number of the panelboard.

31–10. Conduit and Cable Schedules

The intent of the conduit and cable schedule is to provide all pertinent information to assist in installing, connecting, identifying, and maintaining control and power cables. When not included with the plans for construction bids, the specifications should include the cable schedules as an attachment. Each cable and conduit should be identified with an individual designation as described in Table 31–1. See Figure 31–1 for an example conduit and cable schedule format.



CONDUIT			CABLE						DESCRIPTION				REMARKS
NUMBER	SIZE	LGTH.	NUMBER	NO. COND.	SIZE	INSUL.	LGTH.	OPR. VOLT	FUNCTION	FROM	TO	ROUTING	
BCE1-u1-ER3	¾"	30'	BCE1-u1-ER3	2c	#16	600V	35'	125VDC	DC SOURCE 1 ANNUN.	BCE1	ER3 CABINET	CONDUIT, TRAY	
BCE1-e1-SB	3"	10'	BCE1-e1-SB	2	250kcmil	600V	15'	125VDC	DC SOURCE 1	BCE1	BATTERY SWBD. SB	CONDUIT ONLY	
BCE2-u1-ER	¾"	30'	BCE2-u1-ER3	2c	#16	600V	35'	125VDC	DC SOURCE 2 ANNUN.	BCE2	ER3 CABINET	CONDUIT, TRAY	
BCE2-e1-SB	3"	10'	BCE2-e1-SB	2	250kcmil	600V	15'	125VDC	DC SOURCE 2	BCE2	BATTERY SWBD. SB	CONDUIT ONLY	

Figure 31–1. Example conduit and cable schedule format

a. Conduits should be listed first in columns along the left side of the schedule in the order of their designations under the header “Conduit.” Columns under the Conduit header should include:

(1) Conduit designation.

(2) Conduit size.

(3) Conduit length in feet.

(4) All conduits in a hydroelectric powerhouse should be rigid steel; however, concrete-encased PVC ducts or flexible conduits for equipment connections (3 ft [.9 m] maximum) should be so indicated in the remarks column at the far right side of the schedules, aligned with the conduit designation.

b. The circuits inside the conduits should be listed under the header “Cable,” to the right of the Conduits header. Circuits must be aligned with the conduits by their designations. Multiple circuits in the same conduit should be aligned under the first circuit in the conduit without repeating the conduit designation. Circuits run exclusively in cable tray should be aligned in the cable columns with no conduit designations. Columns under the Cable header should include:

(1) Circuit designation.

(2) Number of conductors (for multi-conductor cables, end with “c,” for example, a single 12-conductor cable is expressed as “12c”).

(3) Conductor size.

(4) Insulation voltage rating.

(5) Circuit length in feet (not the total number of feet of individual conductors).

(6) Circuit operating voltage.

c. Descriptive information about the circuits should be listed under the header “Description,” to the right of the Cables header. Columns under the Description header should include:

(1) Function.

(2) Source equipment.

(3) Destination equipment.

(4) Routing (conduit only, conduit and cable tray, or cable tray only, with further description as required).

d. Remarks to clarify any information or to call attention to something specific should be listed under the header “Remarks,” to the right of the Description header.

31–11. Installation Considerations

Cable pulling calculations should be performed by the designer, or by the installation contractor for approval, for long runs of large, shielded cable. This is necessary to verify if a splice is required at any point to avoid damage to the insulation or shield from pulling tension or from sidewall bearing pressure.

a. Splices should not be permitted if requested by the contractor for reasons of convenience. The contractor must prove the case for a splice by submitting cable pulling calculations indicating that damage is likely due to the length of the pull.

b. Cable tension should be monitored by dynamometers or sensors during the pulling process to verify that a maximum allowable cable pulling tension is not exceeded. If tension rises to dangerously near the calculated limit, the pull should be stopped and a splice should be engineered at an accessible point earlier in the pulling route.

Chapter 32
Grounding Systems

32–1. General

A safe grounding design assures that a person in the vicinity of grounded equipment is not exposed to the danger of electric shock. The grounding system carries current into the earth under normal and fault conditions without damage to the equipment. An interconnected grid of embedded or buried conductors (grounding grid) is the key component of the system. For additional information see IEEE 142 and EPRI EL-5036, Volume 5.

32–2. Safety Hazards

A low station ground resistance alone is not a guarantee of safety. During fault conditions, the flow of current to earth can raise potential gradients enough to endanger a person in the area. IEEE 80 provides detailed coverage of design issues relating to effective ground system design. Grounding system design must limit step and touch voltages to levels below the tolerable levels identified in the standard. The conditions that make electric shock accidents possible include:

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

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

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

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

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

32–3. Field Exploration

IEEE 81 outlines methods for field tests and formulas for computing ground electrode resistances. Sufficient investigation such as ground resistance testing should be done to develop a suitable location for the new grounding grid or an extension to an existing grounding grid. IEEE 81 describes various methods for making the soil resistivity determination. It also provides information on other recognized field measurement techniques.

32–4. Grounding Grid

The resistance to ground of all power plant, dam, and switchyard grounding grids should not exceed 0.5 ohm for large installations. For small (1500 kW) plants, a resistance of 1 ohm is generally acceptable. Practical electrode depth should be determined by field conditions. A depth reaching permanent moisture is desirable for switchyards. The effective resistance, step potential, and touch potentials for a grounding grid with several ground rods in parallel can be determined from IEEE 80. IEEE 367 provides additional guidance on understanding and calculating ground potential rise.

a. *Location*. The depth and condition of the soil upstream from the dam on the flood plain is frequently favorable for placement of one or two grounding grids below the soil in the forebay for powerhouses, which is how most powerhouses were constructed. The leads are then extended to the grounding network in the powerhouse, which in turn has equivalent leads to the ground mat below the switchyard.

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

c. *Types of Grounding Grids*. Topography of the site, soil conditions, and depth of soil above bedrock are factors influencing not only the location, but type of grounding grid used. Some common types (in addition to forebay location) are:

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

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

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

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

d. *Ground Rods*. Copper-clad steel ground rods of 3/4 in (1.9 cm). diameter are usually satisfactory where driving depths do not exceed 10 ft (3 m). For greater depths or difficult soil conditions, 1-in. (2.54 cm) diameter rods are preferred. Galvanized pipe is not suitable for permanent installations. Ground rods cannot be placed too close together or their mutual reactance when ground current is flowing will increase the overall resistance of the mat. Ground rods should be no closer together than twice their length. If adding more ground rods becomes impractical and overall resistance is still too high, the grid spacing between ground mat members must be decreased.

e. *Ground Resistance Test*. A test of the overall project ground resistance should be made soon after construction. Construction contract specifications should contain provisions for adding ground electrodes if tests indicate that this is necessary to obtain the design resistance. Proper measurement of the resistance to ground of a large grid or group of grids requires placement of the test electrodes at a considerable distance (refer to IEEE 81).

32–5. Powerhouse Grounding

The powerhouse grounding grid and its overall network of taps is mostly embedded within the powerhouse concrete and constitutes a concrete-encased electrode as recognized by the NEC. Industry typically refers to this method as a “Ufer” ground. For mechanical strength, these conductors should be not less than No. 6 AWG. Copper bar is preferred for exposed runs. Figure 32–1 shows a typical grounding schematic for a hydroelectric powerhouse having one main unit generator.

a. Provisions for Equipment Ground Connections.

(1) Grounding system access points called ground inserts allow direct connection of the equipment grounding conductor (EGC) at the closest point to the equipment. In such cases, the ground insert represents the grounding electrode, and it is not required to run the EGC back to the power source's ground bus. However, when a ground insert or connection point is not within immediate reach of the equipment, the EGC must be run with the feeder for connection at the source grounding point.

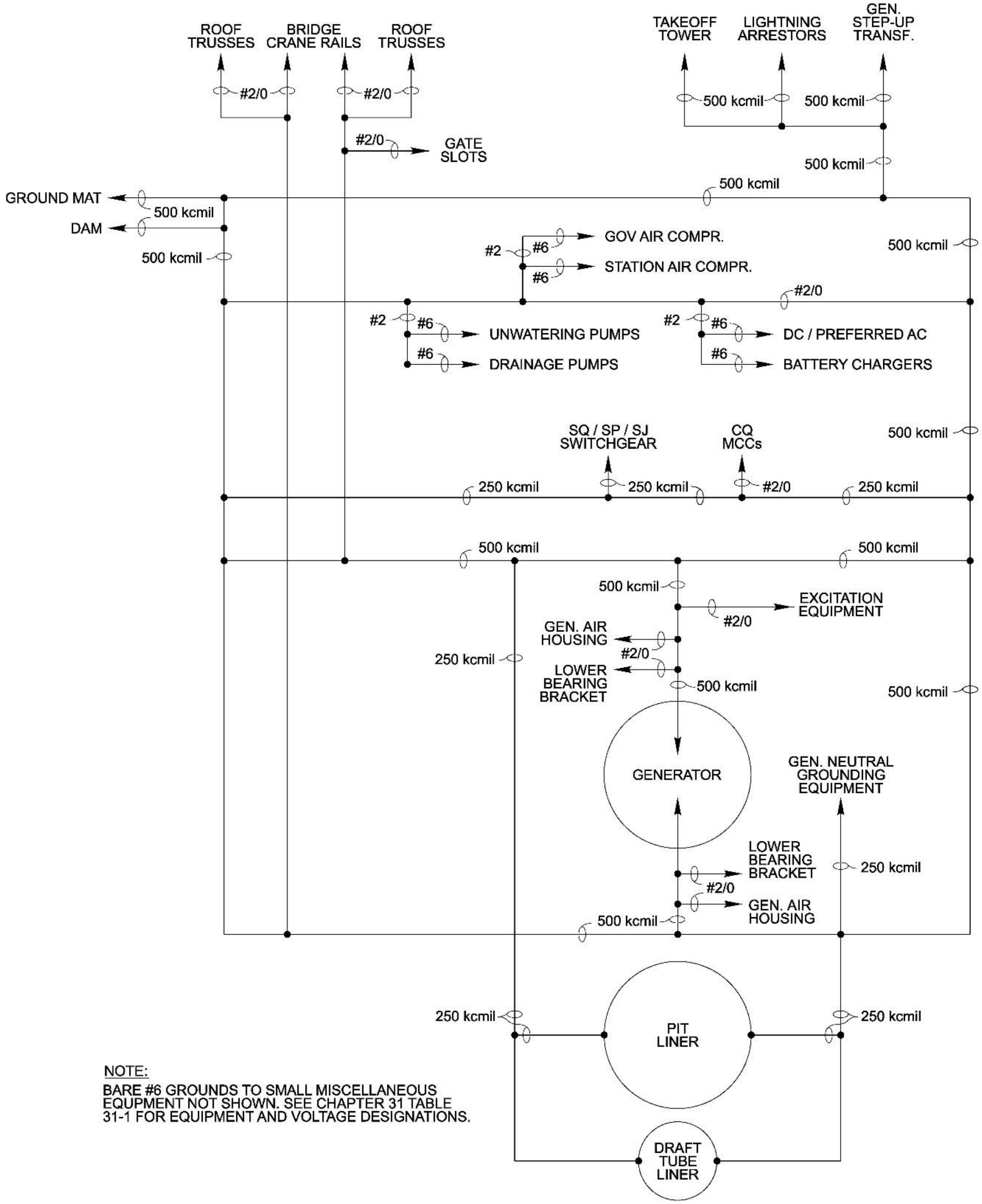
(2) The ground insert is usually a small flush-mounted plate with bolt holes for connection of the EGC. A typical ground insert detail with recommended conductor sizes is shown in Figure 32–2. The connection point may also be a cable coiled in a concrete blockout for attachment using pressure connectors.

b. Powerhouse Equipment to be Grounded. Major items of equipment such as generators, turbines, transformers, and primary switchgear should be connected to this network so there are two paths to ground from each piece of major equipment. Electrically operated equipment in the powerhouse should be grounded with taps from the main ground network where available.

(1) Powerhouse crane rails should be bonded at the joints, with both rails connected to ground.

(2) Roof trusses, draft tube gate guides, and miscellaneous structural steel, which may be exposed to dangerous potentials from energized circuits, should be connected to the ground network.

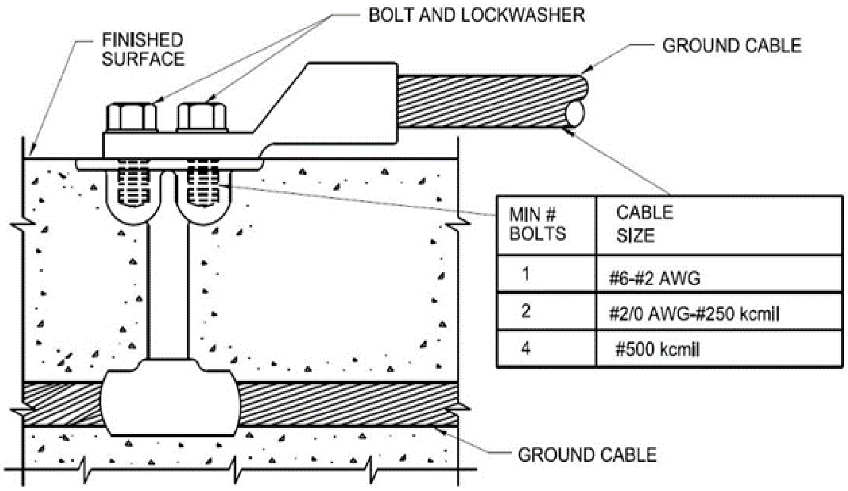
(3) All piping systems should be grounded at one point if the electrical path is continuous, or at more points if the piping system's electrical path is non-continuous.



NOTE:

BARE #6 GROUNDS TO SMALL MISCELLANEOUS EQUPMENT NOT SHOWN. SEE CHAPTER 31 TABLE 31-1 FOR EQUIPMENT AND VOLTAGE DESIGNATIONS.

Figure 32–1. Typical hydroelectric powerhouse grounding schematic



MIN # BOLTS	CABLE SIZE
1	#6-#2 AWG
2	#2/0 AWG-#250 kcmil
4	#500 kcmil

Figure 32–2. Detail of typical ground insert

c. *Typical Conductor Sizes*.

(1) No. 6 AWG: Control cabinets, special outlets, machinery, lighting standards, power distribution equipment with main feeders #2 or less, and motor frames of 60 hp or less.

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

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

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

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

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

32–6. Switchyard Grounding

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

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

c. Switch Grounding Platform. A grounding platform consisting of a galvanized steel grating should be provided at each disconnecting switch handle or motorized operator to keep the person operating the switch at ground potential. The platform should be grounded only to the switch operating rod above the operator and to the steel tower or supporting structure, and in turn, connected to the grounding grid. This prevents fault current from the switch finding a path to ground through the person touching the switch operator.

d. Switchyard Equipment to be Grounded. Switchyard equipment includes:

(1) Tanks of circuit breakers (high-voltage circuit breakers should be connected to the grounding grid so there are two paths to ground from each item of equipment, No. 6 AWG minimum).

(2) Operating mechanisms of disconnecting switches.

(3) Hinged ends of disconnect grounding blades.

(4) Transformer tanks and neutrals (large transformer tanks should be connected to the grounding grid so there are two paths to ground from each item of equipment, 250 kcmil minimum).

(5) Surge arresters (use dedicated conductors to connect surge arresters to the grounding grid to prevent lightning strikes or line surges from passing through other equipment in the path to ground).

(6) Cases of instrument transformers and coupling capacitors.

(7) Medium- and high-voltage potheads.

(8) Steel supporting structures.

(9) Switchyard towers, through one leg.

(10) Isolated conduit runs.

(11) Outdoor cabinet enclosures.

e. Switchyard Fences. Fences, including the hinged side of any gate and the fence at both ends of any gate, should be grounded to the switchyard grid at intervals of about 30 ft (9.1 m).

(1) Fence gates must always open inward to keep the gate and anyone touching it within the zone of protection afforded by the grounding grid. If the fence gates open outward, a ground conductor must be provided approximately 3 ft (.9m) outside the gate swing radius.

(2) If the network does not extend at least 3 ft (.9 m) outside the fence line, separate buried conductors should be installed to prevent a dangerous potential difference between the ground surface and the fence. These conductors should be connected to both the fence posts and the ground network in several places.

f. Overhead Ground Wires. Overhead ground wires, also called static ground wires, should be bonded securely to the steel structure on one end only and insulated on the other end to prevent circulating current paths. They may also be grounded in the middle with both ends insulated. UL 96A offers guidance on placement.

g. Ground Impedance and Ground Potential Rise. Grounding grid impedance and ground potential rise during a fault should be calculated during design for guidance on creating a safe installation. Actual impedance should be tested and documented after construction. Testing for ground potential rise is more difficult as it requires a simulated fault current and sophisticated software. These post-construction tests made by certified professionals should be included in switchyard construction contracts.

32–7. Installation Considerations

a. *Cables*. Grounding cable used for direct burial or embedding in concrete should be soft-drawn bare copper. Sizes larger than No. 8 AWG should be stranded.

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

c. *Exterior Connections*. Ground cable connections to driven ground rods, any buried or embedded connections, or any exposed ground grid connections should be made either with an exothermic molded powdered metal weld or by a copper alloy irreversible pressure connector meeting UL 467 requirements, and preferably IEEE 837 qualified for substations.

d. *Interior Connections*. Pressure clamp (bolted) terminal lugs meeting UL 467 requirements should be used for interior work. For neatness of appearance of interior connections, embedded grounding cables may terminate on or pass through grounding inserts installed with the face of the insert flush with the finished surface. Connection to the apparatus is made by bolting an exposed strap between a tapped hole on the insert and the equipment frame.

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

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

g. *Conduit*. Grounding conductors run in steel conduit for mechanical protection should be bonded to the conduit using grounding bushings.

h. *Grounding*. Cable sheaths and shields should be grounded at one end only. EPRI EL-5036, Volume 5, Table 4.7 provides guidance for power cable shield grounding depending on feeder conductor size, configuration, and length.

Chapter 33
Conduit and Cable Tray Systems

33–1. General

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

33–2. Conduit

a. Rigid metal conduit (RMC) made of galvanized steel is preferred for physical integrity. RMC should be hot-dip galvanized on inside and outside surfaces, conforming to ANSI/NEMA C80.1. Electrical metallic tubing (EMT), intermediate metal conduit (IMC) and aluminum should be disallowed, as they have thinner walls and are more susceptible to damage. Where short lengths of conduit are subject to induced currents by individual phases of medium-voltage or high-voltage feeders fanning out for termination, rigid aluminum may be permitted. RMC is also commonly known as rigid galvanized steel (RGS). Note that the NEC refers to this type of conduit as RMC, whereas the dual ANSI/NEMA standard for this type of conduit refers to it as electrical rigid steel conduit (ERSC).

b. Where practicable, all conduits should be concealed. In cases where allowance must be made for circuits to future equipment, the conduit extension may be exposed. Connections to equipment subject to vibration should be made with liquid-tight, flexible steel conduit, but limited to 36 in. (.9 m) in length.

c. Conduit size is determined by the type of wire and number of circuits in the run, according to the NEC, Tables in Article 310 and in Annex C.

d. Where conduits cross building contraction joints, the conduit runs should be perpendicular to the joint and expansion fittings installed to provide movement of the conduit and to maintain an unbroken ground path.

(1) For conduit runs embedded in concrete, the expansion fitting should compensate for movement in any direction. The fitting should have a suitable neoprene or silicone sleeve to accommodate differential movement of the concrete and an internal bonding jumper. The fitting should be installed so that it is centered across the joint.

(2) For exposed conduit runs, the expansion fitting should compensate for linear displacement. The fitting should be provided with external ground straps for visual indication of bonding.

e. Supports for exposed conduits that are not directly attached to a wall or ceiling, such as struts or threaded rod trapezes hanging from the ceiling, must be braced for seismic motion suitable for the seismic zone of the installation.

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

g. Conduit should be grounded according to Chapter 32. Conduit should not take the place of an equipment grounding conductor in a powerhouse, even if permitted by the NEC.

h. All conduits except lighting branch circuit conduits should be listed in the conduit and cable schedule.

i. For powerhouse substructure work, if conditions are such that embedded galvanized conduit might rust out, consideration should be given to installing exposed runs that can be replaced.

j. Galvanized conduit buried in the switchyard should be protected with a coat of bituminous paint or similar material (PVC coating is permitted). However, this usually doubles the cost of conduit. If experience at the particular site has demonstrated that no special protection is needed on the galvanized conduit, or if the soil resistivity is over 2,000 ohm-cm, the conduit need not be coated.

k. The materials used for boxes and cabinets should conform to those used for the conduit system. Cast iron boxes should be used with galvanized conduit in embedded and exposed locations at and below the generator room floor level. Galvanized sheet-steel boxes are acceptable in locations above the generator room floor. Suitable extension rings should be specified for outlet boxes in walls finished with plaster or tile.

(1) Large cabinets used for pull boxes, distribution centers, and terminal cabinets are usually constructed of heavy gauge, galvanized sheet steel by the manufacturer. Boxes that are fabricated in the field by the contractor should use pre-galvanized steel sheets, and the galvanizing repaired by metallized zinc spray after fabrication. Field fabrication should be limited to providing the equivalent of a NEMA Type 1 enclosure

(2) If a cabinet is embedded in a wall finished with plaster or tile, special precautions should be observed to ensure that the face of the installed cabinet is flush with the finished wall. Front covers are generally mounted with machine screws through a box flange drilled and tapped in the field to facilitate proper alignment. The requirements of UL 50 should be considered as minimum for the design of fabricated cabinets. Provision should be made for internal bracing of large cabinets to prevent distortion during concreting operations.

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

33–3. Cable Trays

Cable trays are commonly used to route groups of cables within the powerhouse between different locations for power, control, and annunciation. Trays in place of conduit provide flexibility, accessibility, and space economy. Trays are also used for the interconnecting cables between switchboards in the control room, and from switchboards to the terminations of embedded conduits running to equipment. Short runs of trays may be used to connect two groups of conduit runs where it is not practicable to make the conduit runs continuous.

a. Cable Tray System Design Considerations.

(1) The designed tray system should provide the maximum practicable segregation between control circuits and power and lighting circuits. The NEC requires segregation of different insulation voltage ratings. Guidelines for cable tray system design are provided in IEEE 422 and in NEMA VE 1.

(2) Cable tray may be ladder type or ventilated trough. Although wire mesh basket wireway may be used at some powerhouses, it should never be substituted for ladder or trough cable tray in new construction or rehabilitation projects.

(3) The NEC allows metallic cable tray to serve as the equipment grounding conductor (EGC) for circuits in the tray, and it also allows splice plates to bond sections together; however, preferred powerhouse practice is to run a bare No. 4 AWG copper grounding conductor alongside the tray, bonding all sections together, and providing separate EGCs for all circuits not bonded to the powerhouse grounding grid.

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

b. Cable Tray Installation Considerations.

(1) Cable trays are installed on fabricated galvanized steel supports designed and anchored to the powerhouse walls and/or ceiling to provide a rigid structure throughout. Guidelines for cable tray system installation are provided in NEMA VE 2. In cable spreading rooms, the tray supports may extend from the floor to the ceiling to provide the necessary rigidity. The support components and their installation method should be seismically certified by the manufacturer for the proper seismic zone where the project is located. Seismic restraints and calculations should be provided for tray systems suspended from ceilings or freestanding above floors.

(2) Supports similar to cable racks are suitable for supporting cable trays on cable tunnel walls. If trays run through the center of a tunnel, they should be supported on structural members such as channel with angle cross-pieces and allow a minimum 3 ft (.9 m) of clearance on both sides to the tunnel wall.

(3) Splice plates are required at all concrete expansion joints, and be securely fastened at one end only to allow axial movement.

(4) Feeder cables should be restrained against the electromagnetic forces resulting from fault current by cable cleats. Cleats are highly preferred for all installations. Conventional wire ties are not suitable for restraint of large conductors where high fault currents are available, and may damage the jackets or shields of even smaller gauge cables subject to lower fault currents. The calculation of proper cable cleat installation and spacing may be performed by the contractor as a submittal for approval in the cable tray specifications, but the available fault current must be provided in the specifications.

33–4. Transmission-Style Suspension Method for Large Cables

The maximum recommended size conductor for cable tray is 1,250 kcmil. Although cables may be special ordered in larger sizes up to 3,000 kcmil, such cables have been known to cause damage to themselves and to cable tray under normal thermal expansion and contraction, especially when cleated to the tray. For cables this large, a transmission-style of hanging cables over saddle-type supports is recommended. Figure 33–1 illustrates this “transmission style” concept.

a. In a transmission-style system, the cables must be cleated to the saddles, with sufficient sag between saddles to accommodate expansion and contraction. Sag calculations must be performed for a specific temperature, and the cables must be installed at that temperature in a controlled environment to the calculated sag.

b. Short-circuit effects must be considered to determine the need for mid-span restraints between cables.

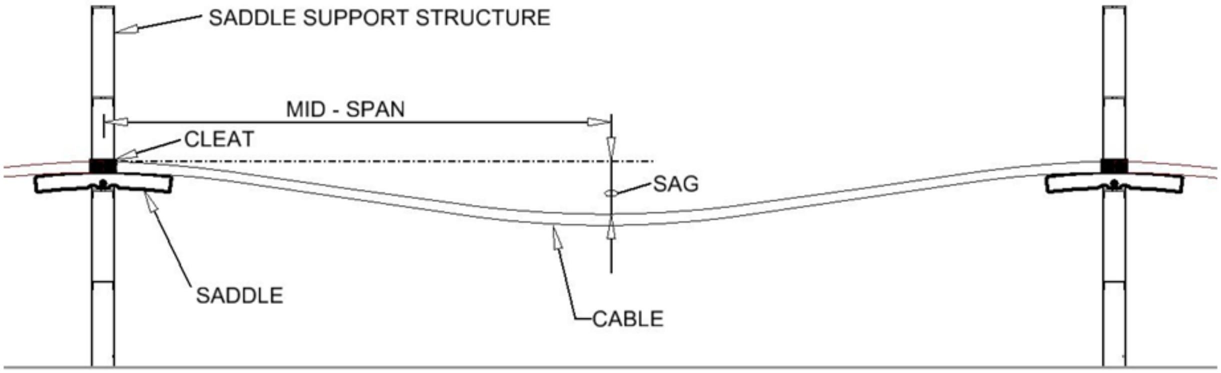


Figure 33–1. Suggested transmission-style method of cable support for over 1,250 kcmil

Chapter 34
Communications

34–1. General

Reliable communication systems are vital to the operation of every power plant. Voice communication is a necessity at all plants, and code-call signaling is generally required for accessing personnel at large power plants. Additional dedicated communication systems are required for telemetering, SCADA, computer-based DACS, and for certain types of protective relaying. Communications media available for power plant application include:

a. Metallic cable pairs.
b. Leased lines.
c. Radio frequency communications.
d. Terrestrial microwave.
e. Fiber optics.
f. Satellite communications.

34–2. Voice Communication System

a. Telephone Service.

(1) Normally, general internal and external telephone communications are provided through public switched telephone network services installed and operated by the serving telephone company or provided through voice over IP (VOIP) by the organization enterprise IT service team.

(2) For telephone landline service, the equipment (including telephones) is leased from the telephone company. The communication circuits provided by a commercial telephone operating company include connection to local exchange, long distance, Networx, or EIS (Enterprise Infrastructure Solutions).

(3) For VOIP telephone service, the organization enterprise IT service team provides the equipment and service.

(4) Telephone stations in visitor areas should be provided for public convenience.

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

c. Telephone Locations.

(1) To ensure adequate telephone access, sufficient telephone outlets should be provided in the office area, the control room, the generator floor at each unit, the switchgear area, the station service area, the plant’s repair shops, and elevators. A telephone outlet should be provided in each elevator cab.

(2) Circuits to telephone outlets are provided by metallic cable pairs. Telephone wiring inside the plant, from the telephone company switching equipment location to the location of the various instruments, is provided by the Government and included in the powerhouse design. Embedded conduits dedicated to telephone use are provided for the cables.

34–3. Dedicated Communications System

a. *General*. Dedicated communications systems are provided in the plant for code call systems, SCADA systems, protective relay systems, and for voice communications to the dispatching centers and substations of the power wheeling entity (either PMA or non-federal utility).

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

c. *Utility Telephone Systems*.

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

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

d. *Leased Circuits*.

(1) Leased commercial circuits can be used for voice communication circuits. Voice grade communication channels are required and are supplied either through a dial or a dedicated system, with dedicated channels being the preferred alternative. A typical voice channel requires at least 3 kHz of bandwidth. Other commercially available private line data channel services are digital data service (DDS) and basic data service (BDS). These latter services offer digital interconnectivity through a wide range of data transmission speeds.

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

(3) Leased circuits have been used for SCADA system control of plants and substations. For locations without existing connectivity, a dedicated connection can be leased for a monthly cost. The costs are based on the physical distance between the

locations and the bandwidth or speed required. T1 circuits typically provide a transmission of 1.544 Mbps and may be adequate for HMI data, but the use of video may require additional bandwidth. T3 and T4 lines may also be available for lease in some locations across the country.

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

e. Microwave Radio.

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

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

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

(4) A microwave radio link can be more cost-effective than leased lines and trenched fiber optic cable. It avoids the trenching and installation costs of fiber optic cable and the monthly recurring costs of leased lines. The microwave link can also prove more reliable than land-based technologies. The microwave link can be established faster than a cable connection, but transmission or “link” distances may be

limited. Licensed and unlicensed bands are available between 2 and 42GHz. The microwave link must be properly designed to ensure topographic and atmospheric conditions do not interfere with the propagation of the radio signal.

(5) Distance to the antenna, antenna location, and wave guide routing must be considered. The effects of icing on the antenna may require a power source for the antenna location to provide antenna heating.

f. Radio. Spread-spectrum radios can be used to provide connectivity between a power plant and an adjacent structure. The technology often requires line-of-sight transmission and is used for shorter distances. Manufacturers should be consulted when considering a radio connection as they can provide test equipment to evaluate its feasibility. Wireless transmissions must be encrypted using DoD approved cryptography.

g. Fiber-Optic Cable.

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

(2) Single-mode and multi-mode fiber optic cabling may be used to establish an Ethernet connection between locations. Industrial Ethernet switches with fiber optic ports should be managed switches to meet cybersecurity requirements. Defense Information Systems Agency maintains an approved products list at https://aplits.disa.mil. Industrial switches on the approved products list are limited, but approved products should be used when feasible.

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

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

(5) Probably the most important application for fiberoptic technology is for a LAN within the plant. Its large data capacity, high data transmission speed, and immunity from EMI make the LAN an ideal medium for communication among the elements of DCS within the plant. The technology is developing rapidly, and standards are coming into being, such as the Fiber Distributed Data Interface (FDDI), allowing its use with a variety of devices.

h. Satellite Communications. USACE has made use of a satellite time signal to provide a uniform time signal to plant control systems, but that signal is available to any suitable receiver without charge. Though this alternative appears to have many attractive advantages, the utility industry in general has yet to implement widespread use of private networks based on satellite technology.

34–4. Communication System Selection

a. General. The HDC should be consulted in the design of communication systems, networks, and interconnections for control systems, SCADA, and DACS, internal and external.

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

(1) *Communication to a PMA.* A standard protocol, such as IEC 60870-6 (TASE.2), Inter-control Center Communication Protocol (ICCP), should be used to exchange real-time data with the PMA. The links between the PMA and the power plant should be managed by firewall/routers. The security of the information being passed on the ICCP links should be protected with NIST FIPS 140-2 approved encryption mechanisms. All access to the ICCP equipment should be controlled by authentication methods to validate the approved users, and users are required to login.

(2) *Communication to the Business Network*. The power plant SCADA may require a connection to the business network to transmit power plant operational data to external organizations. A unidirectional security gateway (data diode) should be used to partition the SCADA network from the business network.

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

d. Internal Plant Communications. Internal data circuits (networks) are needed for the data acquisition and control equipment that uses them. Control systems equipment integrates the operations of the power plant's major electrical and mechanical components. Control equipment also includes remote SCADA systems for centralized control, computer-based DACS for automatic control, and reporting systems, including cyber-secure communication paths, wide area, local area, and other digital networks, sequence of event (time tagging) recorders, video display terminals for data display and operator command (man-machine interface) input.

(1) Discrete control system networks may require connection to the power plant SCADA or DACS for data acquisition and control functions. The communications connection could be serial or via routable protocol, depending on the interface availability.

(2) Also, for large plants to be staffed with administrative and maintenance personnel, a network of microcomputers may be added after the plant is in operation. The plant designer should provide facilities for routing network data highways between offices, maintenance shops, and the control room.

34–5. Reliability

a. A communications channel consists of an assembly of wires and cables, electronic equipment, power supplies, terminations, towers, and other apparatus. Each individual communications channel should be reviewed from end to end with a list of all equipment that is involved. Account for possible redundant paths and a combination of series and parallel-connected equipment. If there is any AC-dependent equipment in series with the channel, assume the channel will not function in the event of a power failure or blackout.

b. Reliability calculations can be complicated when public facilities are involved. Many telephone systems include significant redundancy in common equipment. However, very few, if any, public telephone systems are designed for 100 percent service. Dial-up circuits are particularly vulnerable to overloading (access denial) during emergency situations. Dedicated virtual private networks can be more reliable, but there is no guarantee that a higher priority user (Government or public safety, for example) will not preempt the virtual network. Very few public network facilities are AC independent.

c. In the reliability assessment, identify points in the network that represent a single point of failure. The assessment should include how each element (or its function) is mitigated if its failure impedes critical functions. Consider duplicating sensitive items with functional equivalents, but consider using different suppliers so that a weakness in one device does not propagate to the redundant device. If an identified failure impedes performance, determine if that impediment is tolerable or if replicating the equivalent performance is not economically justifiable.

d. The network can become vulnerable to failure if all communications pass through a single device (such as a communications isolator) or are routed through a common space such as an exit cable, cable duct, communications tower, or even an equipment room. Segregating network cabling within the power plant may also afford some protection for accidental damage or a disaster. Segregating pathways external to the power plant reduces the system's exposure to natural and manmade disasters.

e. It is important that critical functions be maintained under all reasonable circumstances, while secondary functions may be compromised without undue effect on the users. Times of stress on the power plant system can bring significant traffic in secondary data transfers that could slow delivery of critical functions.

34–6. Security Requirements

A brief summary of security issues is presented here to acquaint the plant designer with security concepts. At least the following security concepts should be addressed:

a. *Access Control*. Control access to selected devices, information, or both to protect against unauthorized interrogation of the device or information.

b. *Use Control*. Control use of selected devices, information, or both to protect against unauthorized operation of the device or use of information.

c. *Data Integrity*. Ensure the integrity of data on selected communication channels to protect against unauthorized changes.

d. *Data Confidentiality*. Ensure the confidentiality of data on selected communication channels to protect against eavesdropping.

e. *Restrict Data Flow*. Restrict the flow of data on communication channels to protect against the publication of information to unauthorized sources.

f. *Timely Response to Events*. Respond to security violations by notifying the proper authority, reporting needed forensic evidence of the violation, and automatically taking timely corrective action in mission-critical or safety-critical situations.

g. *Network Resource Availability*. Ensure the availability of all network resources to protect against denial of service attacks.

Chapter 35
Lighting and Receptacle Systems

35–1. General

a. The powerhouse lighting system is defined as beginning with the lighting transformers and extending to the fixtures. For purposes of discussion, it also covers 480V and 120V convenience outlets and corresponding circuits.

b. Several schemes should be considered, and a scheme adopted that gives the lowest overall cost without sacrificing simplicity of design or efficiency of operation.

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

(a) A 480–120/240V, single-phase transformer with 120/240V feeders and branch circuits. This could be a load center and transformer located in a motor control center.

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

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

(a) A 480–120/240V, single-phase transformer, feeding panels with 120/240V branch circuits. This could be a load center and transformer located in a motor control center for local distribution.

(b) A 480–120/208V, 3-phase, 4-wire transformer, feeding panels with 120/208V branch circuits. This is preferable when many branch circuits are required, to help balance the loads across the phases.

(c) Although 480Y/277V, 3-phase, 4-wire lighting systems are popular in large-scale commercial facilities for 277V fluorescent lighting, these systems require a solidly grounded neutral at the station service transformer, which is not advisable for continuity of service (see Chapter 15).

35–2. Illumination Requirements

a. *Intensity Level*. Lighting intensity levels specifically for power plants such as hydroelectric powerhouses are found in European Committee for Standardization (CEN) 12464-1. These levels align with Illuminating Engineering Society of North America general recommendations for offices and manufacturing facilities. See Table 35–1 for recommended minimum illuminance for various areas of powerhouses.

Table 35–1
Recommended minimum illuminance levels for powerhouses

Area	Minimum Illuminance Level
Control Rooms – Traditional Switchboards	50 fc/500 lux
Control Rooms – Computer screens, displays	30 fc/300 lux
Galleries, Storage Areas	10 fc/100 lux
Stairs	15 fc/150 lux
Offices, General Spaces	20 fc/200 lux
Equipment Rooms	20 fc/200 lux
Switchgear Bays	20 fc/200 lux

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

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

d. Specific Conditions. For general areas, the zonal cavity method of illumination design is considered satisfactory. For special conditions such as illumination of the vertical surfaces of switchboards, a careful check by the point-by-point method may be needed. Take care to minimize reflected glare from the faces of switchboard instruments. To facilitate design review, the manufacturer’s candlepower distribution curves should accompany the design drawings.

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

35–3. Efficiency

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

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

(1) *Light-Emitting Diode*. Light-emitting diode (LED) fixtures do not have a "lamp," but have a cluster of LEDs in a lighting unit powered by a driving unit in much the same way that a discharge-type of luminaire has a lamp and a ballast to energize and regulate the lamp. LED luminaires are by far the most energy efficient and should be the first consideration for a lighting rehab or new lighting design. Luminaires are designed for ceiling and wall installation, as well as for high-bay and outdoor area lighting. See the Illuminating Engineering Society (IES) publication IES G-2 for more information.

(2) *Incandescent and Tungsten*. In general, these lamps provide the "whitest" light, but at a higher energy cost and relatively short life. UFC 3-530-1 recommends against their use if any LED or other type of source is available. Incandescent lamps may remain in use as task lighting where fluorescent fixtures are not practical or there is a need for superior color rendition, as long as recurring lamp replacement costs are less than the cost of fixture replacement with LED fixtures.

(3) *Fluorescent*. Modern fluorescent lamps are triphosphor types having three different phosphors. Such lamps produce about 10 percent more light output and can be made with better color rendering ability and higher temperatures (color appearance) than older lamps with one phosphor. Most rooms and shops should be illuminated with fluorescent fixtures using T-8 high-efficiency lamps and electronic ballasts. T-12 lamps are less efficient and should not be used. No fluorescents should be used outdoors or in ambient temperatures below 50 °F.

(4) *High-Intensity Discharge (HID)*.

(a) UFC 3-530-1 no longer allows mercury vapor lamps. The amount of mercury required for these lamps posed a disposal hazard. If existing mercury vapor fixtures encounter a failed ballast, the entire fixture must be replaced with a different type of fixture.

(b) Metal halide lamps are a good source of "white" light, covering about 70 percent of the visible spectrum and are suitable over large areas for interior high-bay lighting or exterior security lighting. They have good life and are very efficient. Their disadvantages are relatively long start and restart times.

(c) High-pressure sodium (HPS) lamps are very efficient, but are a poor source of white light, covering only about 21 percent of the available spectrum. They need about 3 or 4 minutes of start time, and about 1 minute of restart time. HPS should be limited to outdoor use.

(d) Low-pressure sodium (LPS) lamps are more efficient than HPS lamps, but produce almost no white light. Their use is limited to outdoor lighting. Poor color rendition and hazardous disposal concerns over the amount of sodium required for LPS lamps have driven industry to cease manufacturing them, although they are still available from some sources. LPS should never be considered for switchyard lighting as the almost total lack of color rendition at night could prove hazardous in a switchyard environment.

c. Evaluation. When designing the lighting system, the above sources should be considered and the most efficient combination of sources used, appropriate with achieving design lighting levels and good lighting quality. Evaluation and choice should consider both energy and maintenance costs, as well as initial cost of the fixtures.

35–4. Conductor Types and Sizes

The voltage drop in panel supply circuits should be limited to 1 percent if possible, and the drop in branch circuits should be limited to 2 percent. If it is not possible to limit the voltage drop to these figures, a limit of 3 percent for the total voltage drop should be observed. In arriving at the voltage at the load, the impedance drop through the transformer should be considered, although this drop need not be considered in feeder or branch circuit design.

35–5. Emergency Light Control

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

35–6. Control Room Lighting

a. General. Many different schemes have been attempted in developing ideal control room lighting, due to the difficult and continuous visual tasks that are performed in the control room. Task ambient lighting provides the most effective approach to achieving desired results.

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

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

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

(1) Adequate vertical illumination on vertical board surfaces.

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

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

(4) No objectionable shadows on working surfaces.

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

35–7. Hazardous Area Lighting

Battery rooms and oil storage rooms are not actually classified as “hazardous” under the NEC Article 500. Explosion-proof lighting fixtures are not required; however, fixtures in these areas should be vapor-proof type, and local control switches should be mounted outside the door. Lighting switches of the standard variety may be used by placing them outside the room door. Convenience receptacles in the rooms should be avoided.

35–8. Receptacles

The types and ratings of receptacles for convenience outlets should be clearly indicated on the fixture and device schedule sheet in the drawings, or in the bill of materials. Receptacles should comply with UL 498 and NEMA Wiring Devices (WD) 6. Boxes should be metallic in compliance with UL 514A. Plastic boxes must not be permitted, as all wiring must be in metal conduits as described in Chapter 33. The following receptacles are suggested as the appropriate quality and type:

a. 480-Volt Receptacles. Although 480 volts is not considered a “lighting voltage,” 480V receptacles are common in powerhouses and are included here. They are typically used to power portable welding equipment. Amp ratings may be 30 A, 60 A, or 100 A. The preferred configuration is pin-and-sleeve type conforming to UL 1682 and UL 1686, 3-pole, 4-wire, grounded through the extra pole and the shell of the plug. The receptacles and plugs should be weather resistant for use in wet and dry locations (NEMA 3R or NEMA 4 construction) even if used indoors. Arc flash concerns can be addressed by using “switch rated” plugs and receptacles conforming to UL 2686.

b. 120/208-Volt Receptacles. 4-pole, 5-wire, 30 A, grounded-type receptacles may be used to service supplemental lighting in work areas during overhauls or portable 120/208V equipment. They are intended for three-phase loads with a neutral and may be either pin-and-sleeve or twist-lock type.

c. 120-Volt Receptacles. The choice between using a twist-lock receptacle or using a parallel-blade receptacle has never been standardized nationwide. There is a trend to employ parallel-blade receptacles on new construction projects. Parallel-blade receptacles are recommended unless there is a strong local preference for twist-lock receptacles based on existing local standardization. Ground fault protection must be provided for 120V outlets in all wet locations or outdoors. Use appropriate ground fault interrupter circuit breakers in these locations where the receptacles do not come equipped with integral ground fault interrupters, and provide a label indicating that ground fault protection is provided at the circuit breaker.

(1) *Twist-Lock Receptacles*. For projects using twist-lock receptacles, 2-pole, 3-wire, 15-A, 125V, grounding, duplex, twist-lock, NEMA L5-15R configuration for use with compatible twist-lock caps are recommended for dry locations within all powerhouse areas. For wet locations or outdoors, a similar single-gang receptacle in a cast box with twist-lock caps or plugs is recommended. For lunch rooms, office areas, lounges and restrooms, duplex combination, twist-lock, straight-blade receptacles, NEMA L5-15R configuration, are recommended.

(2) *Straight-Blade Receptacles*. For projects using straight-blade receptacles, 2-pole, 3-wire, 20-A, 125V grounding, duplex, hospital grade, NEMA 5-20R configuration, are recommended for dry locations. For wet locations or outdoor use, single, hospital grade receptacles in the same configuration, with weatherproof single-receptacle cover plates are recommended.

Chapter 36
Heading, Ventilation, and Air Conditioning

36–1. General

a. Powerhouse HVAC is required to maintain temperature and air quality conditions suitable for operating equipment and safe for plant personnel. Maintaining required conditions for operating equipment is essential under all weather conditions at the site. Personnel and visitor design conditions are also important. Where equipment conditioning is not required, ASHRAE air standards should be followed for energy conservation.

b. Any new equipment installations should consider the increased energy efficiency of modern systems and apply new computer-aided modeling methods to determine cooling and heating demands.

c. New equipment must not contain Class I ozone depleting chemicals (ODC), including all chlorofluorocarbon compounds (CFC), halons, or their mixtures.

36–2. Design Conditions

a. *General*. Assumed design conditions, both outside and inside the powerhouse, have major effects on system adequacy, construction costs, and operating costs, since they influence the type of equipment provided. Sufficient engineering time for research and coordination of available data, including drawings at a minimum, and preferably also computations, commissioning reports, and O&M manuals, is essential to a practical design. Data used in equipment and process selection should be provided via ASHRAE or verifiable recorded conditions of the site. Use UFC 3-410-01 Heating, Ventilating, and Air Conditioning for minimum design conditions. These records should be included in any design manual or calculations used to select new equipment.

b. *External Conditions*.

(1) *Weather*.

(a) Sources of weather data include the latest edition of ASHRAE Fundamentals Handbook, UFC 03 400 2 (https://climate.af.mil) power plants in the area, and public records. The ASHRAE handbook is a reliable source for listed locations, but power plant locations are frequently some distance away from a listed location, and design conditions can be appreciably different in 50 miles (80.6 km) or less. In such cases, the designer should research other available data for applicability and authenticity. When other reliable data is unavailable, the interpolation procedure outlined in the ASHRAE handbook should be used. Indicate the method used to reach baseline weather data conclusions in design calculations.

(b) Weather data and design conditions as listed in the ASHRAE Fundamentals Handbook chapter for climatic design information are preferred and should be included in the mechanical design memorandum. Duration of hot and cold extreme temperatures is not usually included but is valuable when available to permit the design to reflect the flywheel effect of the normal massive construction of powerhouses. Outdoor design temperatures for comfort heating and cooling should be based on the 2 percent dry bulb and corresponding mean coincident wet bulb temperatures, respectively. Outdoor design temperature for heating to prevent freezing conditions should be based on the 1 percent dry bulb temperature.

(c) Evaluation data other than ASHRAE should be evaluated based on location of readings, periods of record, probable dependability, and cross-checking to arrive at appropriate outside design conditions. The data should be combined and presented as nearly as practicable in the form noted in ASHRAE Fundamentals chapter on climatic design information. Mechanical design memoranda should include the evaluation factors along with basic data and the assumed design conditions.

(2) *Groundwater Temperatures*. Groundwater temperatures are usually available from the general design memorandum or other previous memoranda. Groundwater use is seldom economical for heating and cooling purposes, but temperature conditions are usually available through the U.S. Geological Survey offices. Probable pool water temperatures should be available in the Environmental Impact Statement, General Design Memorandum, or generator cooling water studies, though the averages might change over time. Pool water temperatures also might be monitored by the project. Summer and winter water temperatures should be included in the design conditions data along with the data source.

(3) *Ground and Rock Temperatures*. General information on ground and rock temperatures is available in the ASHRAE Fundamentals Handbook. Because of the limited effect on system design, extensive research is usually not warranted. The design memorandum should include the ground and rock design temperature, and the source or basis of assumption. Underground equipment, piping, or structures below ground level should be evaluated for environmental impacts due to freezing. The latest edition of “ASHRAE Fundamentals” should be consulted for frost line depth and the result recorded in the design memorandum.

c. *Indoor Conditions*.

(1) *General*. Indoor design conditions should consider project personnel comfort equipment requirements. Personnel and visitor requirements are somewhat flexible, allowing deviations during extreme outside conditions. Indoor occupied conditioned areas such as offices and control rooms should be maintained at the ASHRAE – 55 standards.

(2) *Temperature and Humidity for Personnel*. Indoor design temperature varies with many factors, such as occupancy of the powerhouse, type of equipment, and sponsor/owner requirements. The control room office and visitor rooms should be heated and cooled to 68.5 to 75 °F (20.3 to 23.9 °C) (winter) and 75 °F to 80.5 °F (23.9 ° C to 26.9 °C) (summer) respectively. Rooms with equipment that is sensitive to freezing conditions should be heated to a minimum of 40 °F (4.4 °C). Maximum humidity conditions should generally be limited to 50 percent in the office, control room, and visitor area.

(3) *Temperature and Humidity for Equipment*. Equipment maximum and minimum conditions are more critical, as deviations could affect plant capability or subject equipment to damage. Humidity control for equipment must be considered. Increased digitalization of powerhouses is likely to affect required design conditions, because the electronics require a certain range in temperature and humidity. Significantly shorter design life may be expected for some controls if HVAC capacity is not updated accordingly. Consult equipment manufacturer for required humidity capabilities of the equipment.

(4) *Ventilation*. Ventilation rates should be consistent with ASHRAE 62.1. Equipment/gallery rooms and turbine pits generally should have minimum air exchange rates of 1 and 4 air change per hour, respectively. Battery rooms are to be designed using UFC 3-520-05 Stationary Battery Areas. Occupied areas are subject to the minimum outdoor air flow defined in ASHRAE 62.1 Ventilation for Acceptable Indoor Air Quality. Provide required design amount per occupied space. For large spaces, CO_2 sensors or occupancy sensors should be used to save costs of conditioning outdoor air.

36–3. Design

a. General.

(1) The system design should be based on criteria, factors, and details recommended or indicated in the ASHRAE Fundamentals Handbook and applicable UFC. The design should be conservative while providing acceptable operation with normal decreases in operating efficiency and average maintenance.

(2) Each HVAC system should be designed to operate efficiently during normal conditions for that space. Providing equipment capable of handling extreme load cases increases cost and decreases overall efficiency. Heat gains from lights and equipment should be included in both heating and cooling load requirements. The use of a computer aided heat and cooling load calculation software is strongly advised when modifying existing spaces with changes in occupancy or equipment to confirm required airflows.

(3) Include heating and cooling load results in the design memorandum.

b. Insulation.

(1) Powerhouse insulation is not normally a direct design responsibility for hydropower engineers. However, because of its influence on the required heating and cooling provisions and energy requirements, hydropower engineers should be involved in project planning affecting insulation provisions. The most practical applications for insulated construction are usually the powerhouse walls above the bridge crane rails and roof. Consult the latest edition of ASHRAE 90.1 for insulation and window U-value requirements.

(2) During alterations or modifications where old insulation is removed, care should be taken to ensure no asbestos containing materials are present.

(3) Any insulation or windows replacements should conform with current ASHRAE 90.1 U-value guidance.

c. Heating.

(1) *General*. With the required emphasis on energy conservation, studies on the heat source and type of conversion equipment merit major design attention. Several options are open in most cases, and the factors pertinent to the selection should be included in the design studies and the design memorandum. System layout, equipment, and details consistent with ASHRAE fundamentals and reflecting previous powerhouse experience are normally satisfactory. Use computer-aided heat load calculation software to determine heat load; in many cases, equipment heat rejection provides most of the heating required.

(2) *Heat Sources*.

(a) Generator Cooling Water. The waste heat available in generator cooling water should be the prime source in all powerhouses where planned unit operation provides a reliable supply, or where practical modifications in unit scheduling could assure a reliable supply. Any plant with three or more units on baseload operation should have the capability for a continuous supply. Plants with planned intermittent or basic peaking operations may also provide a practical source if agreement on the necessary modifications in unit scheduling can be obtained. One- or two-unit plants located in areas subject to extended periods of subfreezing temperatures should not depend on generator cooling water as the basic heat source because of the limited backup capability.

(b) Solar Heat. Solar heat should be investigated for the powerhouse and visitor facilities. Solar heating studies should be based on the UFC 3-440-01 Facility-Scale Renewable Energy Systems.

(c) Outside Air. Outside air, using air-to-air or air-to-water heat pumps, has limited potential as the basic heat source because of reduced efficiency during subfreezing conditions. A study may be warranted for plants without a dependable water heat source, located in moderate climates.

(d) Pool Water. Pool water may be a practical heat source where winter water temperatures above 45 °F (7.2 °C) can be assured. Use caution in accepting pool water temperature estimates near 45 °F (7.2 °C) as the margin for safe operation is limited, and there are many variables affecting pool water temperatures.

(e) Miscellaneous Water Sources. Groundwater from wells or foundation relief flows can provide water of desirable temperature, but assurance of continued supply is questionable, and these sources are not normally recommended.

(f) Electricity. Electricity used in resistance heating is an available and reliable source at most power plants. In many plants, it may be the most economical. Its disadvantage is the relatively low efficiency in the overall energy supply. Its use in resistance heating as the basic heat source should be limited to plants that meet the following scenarios:

1. Where a reliable more efficient heat source is not available.
2. Where total annual costs of an alternate, more efficient source exceeds the cost of resistance heating by more than 25 percent.
3. Where the total yearly heating energy demand is under 100,000 kW hours per year. Electrical energy used in resistance heating may be employed as required for auxiliary heat in occupied areas and temporary heat for maintenance and repair purposes.

(g) Backup Heating. Backup electric heating should be supplied to normally occupied spaces such as offices and control rooms. This provides a redundant source of heat if the main source is compromised. Preventing freezing conditions in these areas is paramount to continued plant operation.

(h) Oil and Gas. Using oil or gas is typically more cost effective over electrical resistance heating, but in electrical production facilities, it is more efficient and safer to use electric or pool water heating methods. Introducing flammable gases or liquids into a power production area is not recommended.

(3) *Conversion Equipment*. Equipment to be considered for heating is water-to-air coil-type heat exchangers, heat pumps, and resistance heating coils. Heat pump capacity should be sized, or backup resistance heating provided, to assure capacity for maintaining above-freezing temperatures within the powerhouse under minimum outdoor temperature with one compressor inoperable.

(4) *Source Water Piping*. Source water taps and headers should always ensure required water to the coils or heat pumps. The designer should consider where the cooling water supply is acquired (intake or tailrace). Generator cooling water should be supplied through a header connecting to a minimum of three units, but may be justified to all units depending on plant size, proposed plant operation, and weather conditions. Pool water should not be subject to interruption from main unit shutdown involving placement of stoplogs or closure of gates. Strainers in the source water supply should be duplex, with strainer perforations as large as practicable and consistent with heat exchanger requirements. See also Chapter 24.

(5) *Biofouling Mitigation*. Raw water piping systems should be designed to include biofouling mitigation methods when necessary. Contact local water authorities as required for any chemical injection systems that inject to the raw water discharge. The outcome of the biofouling mitigation discussions should be included in the design memorandum.

(6) *Heat Distribution*. The bulk of the powerhouse heat requirements should be distributed through the ventilation system with water-to-air coils. Resistance elements located in air handling units or ducts should not be used unless resistant heat is the only practical method of heating the powerhouse.

d. Cooling.

(1) *General*. Wherever practicable, cooling should be provided by circulating existing powerhouse air and outside air through the ventilation system. Cooling the supply air stream is typically accomplished with raw tailwater through water-to-air coil-type heat exchangers. Where suitable outside air or raw water temperatures are not obtainable, cooling may be provided with chilled water coils in the ventilation system or package-type air conditioning units. Package-type system sizes should be kept at or below 30 tons. Above 30 tons, a chiller-type system is typically more economical. Avoid cooling tower evaporation-type heat rejection processes.

(2) *Cooling Load*.

(a) Outdoor. Outdoor design temperatures should be based on ASHRAE fundamental climatic data as defined above. Allowance for sun exposure is particularly important for exposed gallery structures containing power cables or buses and heat-sensitive equipment. Always consult equipment manufacturer’s design specifications for maximum working temperature allowed.

(b) Indoor. Indoor heat gains are essentially electrical and should be based on equipment manufacturers’ data with conservative efficiencies. It is essential that adequacy of the cooling provisions is not a limiting factor in equipment or electrical conductor operation. It is also important that heat gain estimates be verified for critical areas such as galleries with high concentrations of electrical load. Design memoranda should recognize such areas, show the source or basis of heat gain estimates, and include appropriate factors for contingencies. In plants provided with indoor emergency

diesel generators sets, the heat gains may be of significance and should not be overlooked.

(c) Calculating Cooling Load. Computer-aided cooling load calculation software should be used to determine required cooling loads. Input all known equipment and conductor heat loads. It is beneficial to add approximately 20 percent additional electrical heat load to the heat calculation for future additional demands and inadequate manufacturer equipment heat release data. Develop multiple load cases (worst case maximum load, typical load, light load) and confirm equipment is most efficient in the typical load case.

(3) *System and Equipment*.

(a) General. The bulk of the cooling requirements are normally provided through the ventilation system either with outside air or water-to-air coils located in the air handling units or ducts. Auxiliary or isolated zone cooling using package-type air handling units or package-type air conditioners may sometimes be most practical, typically for the office and control room compartments. Cooling requirements frequently determine maximum ventilation rates, but ventilation supply air should never drop below rates required by ASHRAE 62.1.

(b) Heat Pumps. The joint use of heat pumps for heating and cooling requirements is the preferred method of heating and cooling if direct cooling from outside air or water is not practical. Provide backup heat strips to provide heat during sub-freezing temperatures.

(c) Compressors. Where cooling by mechanical refrigeration is justified, the compressor capacity should be provided with two or more compressors rated to provide approximately two thirds of system requirements with any one compressor out of service for any systems 10 tons and above.

(d) Humidity Control. Dehumidification is normally accomplished, as required, in the system cooling coils. This may be a factor in determining required cooling water temperature. Special cases such as a server room or computer room compartments may warrant additional humidity control.

(e) Direct Expansion Coils. Direct expansion coils in the main air system should be avoided. Chilled water coils are preferred. Direct expansion coils may be used where self-contained package-type air conditioners are justified.

(f) Precooling Coils. A combination of precooling coils using pool or tailwater and chilled water coils may be used to conserve energy where economically justified.

(g) Package-Type Air Conditioners. Simplification of the main powerhouse system and overall increased flexibility may frequently favor using package-type air conditioners with coil, blower, and filter for areas requiring special temperature control. This should be considered in the early design stage to assure space for appropriate locations. Required ventilation and exhaust air and chilled or heated water are normally provided from the central system when package-type air conditioners are used. Locations should provide for convenient access for servicing. Completely self-contained units with direct expansion coils, electric heaters, fans, and filters may be justified for small areas remote from the central system.

(h) Replacement and Repairs. When replacing non-operating chiller or raw water cooling systems, compare design requirements with equivalent package-type units. The simplicity of the package unit increases reliability of the system over time. Repairs can

typically be completed by local HVAC repair technicians and do not require a chiller manufacturer specialist that can have long backlogs to get work completed.

e. *Air Filters*.

(1) *General*. Filters should be provided in all ventilation systems to reduce powerhouse cleaning and maintenance costs, aid in maintaining coil efficiencies, and improve air quality for personnel.

(2) *Type*.

(a) Several types of filters are satisfactory, including the following: electronic precipitator in combination with automatic roll type, throw-away type, replaceable dry media type, and automatic replacing roll type.

(b) Electronic precipitators are the most efficient in removing both coarse and fine foreign material from the air, but range up to double in annual costs over the other types. The other types have similar performance characteristics but differ in maintenance requirements.

(c) Normally, the choice of filter should be from the nonelectronic type with the selection made based on lowest annual cost. Electronic types may sometimes be justified based on unusually clean air requirements for certain equipment or to obtain better air quality for personnel in areas subject to unusually severe pollen conditions.

(3) *Location*. Filters are normally installed in air handling units, ahead of the coils, and in a position to filter both recirculating and outside air. Do not locate filters in hard to reach or unsafe areas. If filter removal and replacement is difficult during normal maintenance operations, those filters will be overlooked for long periods of time.

f. *Ventilation*.

(1) *General*. Ventilation is required as a minimum to assure reasonable air quality conditions throughout the powerhouse. Recirculation normally provides the principal ventilation air with the balance provided from outside air. The minimum outside air is based on the system requirements for rooms requiring outside exhaust, for direct use of compressors and gas or diesel engines, plus an allowance to assure a positive pressure within the powerhouse. Actual ventilation system air handling capability is usually determined by heating or cooling requirements. Provisions for heating, cooling, filtering, and humidity control are included in the system as required. Follow ASHRAE 62.1 for required outside air for each compartment’s individual needs. Avoid dedicated outside air conditioning (DOAS) units if possible.

(2) *Aerating Runners*. Many powerhouses install aerated runners to mitigate undesired water oxygen levels during seasonal water changes. See Chapter 5 for additional details regarding aerating runners.

(a) The air being pulled into the water exit discharge stream is collected from the turbine pit area inside the powerhouse, and the amount of air depends on the runner capabilities and desired DO amounts. Take care to make sure the powerhouse HVAC and ventilation systems are modified to accommodate the additional air requirement for the aeration system.

(b) Obtain worst-case design data from the turbine runner manufacturer and include it in the design memorandum. Analyze existing powerhouse ventilation for accommodation of the aeration ventilation requirements. If the existing system cannot compensate for the increased ventilation rate, a new system must be installed to keep

the powerhouse at a slightly positive pressure even during operation of the aeration system.

(3) *Equipment*. The principal supply and recirculating fans are normally installed in or adjoining air handling units containing heating and cooling coils and filters. Auxiliary heating or cooling coils, booster fans, and exhaust fans are located as required in the overall system. Automatic dampers are normally provided in generator room roof-exhaust ventilators to control the powerhouse positive pressure to approximately 0.1 in. of water for reduction dust intrusion.

(4) *Miscellaneous Considerations*.

(a) Paint Spray Areas. Repair rooms or repair pits with paint spray equipment should be provided with supplemental ventilation for use during painting operations. The installation should conform to the applicable provisions of UFC 3-410-4 Industrial Ventilation, NFPA 33 and 91. Flammable vapor removal requires special fans and fan motors. Additionally, using the exhaust fans for smoke removal elevates the fan temperature requirements stated in NFPA 92.

(b) Emergency Generator Rooms. Rooms with gasoline or diesel engine-driven emergency generator sets should be provided with ventilation to remove heat given off by the generator, exciter, engine surfaces, exhaust piping, and heat exchanger, as well as with ventilation for engine combustion. Ventilation should be provided per ASHRAE 62.1 when the generator is not in use. Consult the engine manufacturer for required combustion air quantity. Consult NFPA 37 for additional ventilation requirements.

(c) Control Room Ceiling. Space above the control room ceiling should be provided with sufficient ventilation to remove the heat given off by the high-intensity control room lighting if equipped. New control room lighting installations should use LED, low heat release fixtures and additional above-ceiling cooling may not be required. Outlets and inlets should be arranged to provide uniform cooling and to avoid hot spots.

(d) Exhaust Provisions. Toilet rooms, oil storage rooms, paint storage rooms, control rooms, rooms with mechanical refrigeration, and similar spaces should be provided with exhaust to the outside during all seasons. Any compartment equipped with a special hazard fire suppression system (clean agent, CO_2) should have a non-shared, non-sparking totally enclosed, fan cooled (TEFC) fan-powered exhaust route directly to the outdoors for use after a discharge of that system has occurred. Any exhaust discharge location may not be located within 10 ft (9.1 m) of any ventilation air inlet. Automatic dampers and variable speed fans are generally used where two or more rates of ventilation are required.

(e) Ducts. Ducts are usually constructed of galvanized sheet iron with suitable stiffeners. Vertical building chases and galleries are often used as ducts, where economical. Galleries are often practical for large-volume air movements but should not be used where normal traffic is heavy and door opening/closing materially affects the operation of the ventilating system. Unbalanced pressure effect on door operation should also be considered, particularly where visitors may have access. Galleries with concentrations of heat-generating equipment may require metal ducts to permit concentrated delivery of cooling air or pickup of exhaust air. Using louvered doors and corridors as a substitute for a return duct on an air conditioning system is unsatisfactory.

1. Insulation for ducts should be provided where required to avoid condensation or where justified to conserve energy. All insulation should be of fire-resistant.

2. No stairwells or main egress corridors may be used to return air to air handling equipment.

(f) *Battery Rooms*. Battery rooms require specialized ventilation equipment and installation procedures in compliance with UFC 3-520-05 and UFC 3-600-01.

g. *Controls*.

(1) *General*. Controls should be the automatic type wherever feasible to minimize required manual input. Use lockable thermostats in a non-monitored location to reduce efficiency and prevent unauthorized adjustment. In summer-winter air conditioning systems, however, the primary changeover should generally be manual to avoid unnecessary heating-cooling cycling during mild weather.

(2) *Design*. The general control system for each powerhouse should be developed along with the overall system layout to assure a well-coordinated design. Emphasis should be on minimizing energy use and obtaining good average conditions in the powerhouse with minimum complexity and maximum dependability. In most powerhouse areas, there is considerable latitude in acceptable conditions, which should be reflected in the control method as well as the system layout. In the interest of energy conservation, control requiring simultaneous cooling and heating should be avoided.

(3) *Controls and Cybersecurity*. Final control system design should be a contractor responsibility. Specifications should require hard-wired control devices. LAN-type control systems are permitted when there is no threat of unauthorized system entry through outside network interference. Wireless data transfer devices are not permitted. All systems should be submitted for approval prior to construction to controls section security specialist.

36–4. Design Memorandum

The design memorandum should include the background information essential to selecting design conditions. The choice of methods of heating and cooling should be discussed and justified. Special conditions that warrant departure from the usual design criteria should be explained. Heat gains and losses should be tabulated by room or space, and summarized by system using a computer-aided design software with results. A flow diagram for each system should be furnished. Separate control diagrams for heating and cooling seasons are desirable on the air conditioning systems.

Chapter 37
Elevators

37–1. General

a. Introduction.

(1) Elevators are used in powerhouses and pump stations for the ingress and egress of personnel and equipment. Most elevators in powerhouses and pump stations are electric traction passenger type with an overhead hoist contained in a machine room. Some facilities have both a passenger elevator and a freight elevator.

(2) Elevators are governed by specialized safety codes that address all aspects of elevator design, safety features, installation, inspection, and testing. Elevator design and function is integral with building life safety function. Elevators should be integrated with other systems in the facility such as fire alarm and detection systems and generation equipment fire protection systems.

(3) All elevator replacement or rehabilitation work performed in powerhouses and pump stations should be evaluated to this section and the latest DoD UFCs and safety codes and standards.

(4) Elevators remain reliable and safe only through regular inspection and testing. A malfunctioning elevator system may cause loss of life or serious injury. Facilities often lack an inspection, maintenance, and records program for their elevator(s).

b. Purpose. This chapter provides information for elevator design, installation, maintenance, and operation. Guidance applies to the installation of new equipment as well as the maintenance and upgrade of existing equipment for architectural, structural, mechanical, electrical, and fire protection design of powerhouse elevators. Elevator replacement or upgrade can require life safety features that may not be contained in original facility construction. Careful code analysis is required to navigate which requirements pertain to the various categories of replacement, upgrade, and renovation as well as the interaction of the elevator with the overall powerhouse life safety features.

c. Elevator Classification. The primary classifications of powerhouse elevators are either passenger or freight. An elevator designed for moving personnel is classified as a passenger elevator. An elevator designed exclusively for moving material(s) is classified as a freight elevator.

d. Elevator Types. The two types of elevators are electric traction and hydraulic.

(1) Electric traction elevators are also known as “electric elevators” and are the most common type of elevators, having been uses since 1900. Elevator cars are pulled upwards by electric motor-powered hoists with steel ropes. The car is guided along rails inside a vertical hoistway, and the weight of the car is balanced by a counterweight. Modern traction elevators may use flat steel belts instead of conventional steel ropes. Flat steel belts are extremely light due to a carbon fiber core and a high-friction coating that does not require oil or lubricant. Most electric elevators require a machinery room and hoist located at the top of the hoistway.

(2) Hydraulic elevators are powered by a piston that travels inside a cylinder. An electric motor pumps hydraulic oil into the cylinder to move the piston. The piston smoothly lifts the elevator cab. Electrical valves control the release of the oil for a gentle descent. An overhead machine room is not required. Hydraulic elevators may be used in buildings up to five or six stories high.

37–2. Special Applications

The powerhouse contains numerous wire rope hoisting devices that may be used to perform specialized conveyance or lifting support. All applications outside of the passenger or freight elevator classifications are addressed in other sections or in other specialized safety codes not included in this section. These applications include:

a. Personnel hoists.

b. Material hoists.

c. Platform lifts and stairway.

d. Manlifts.

e. Mobile scaffolds and towers.

f. Powered platforms and equipment for exterior and interior building maintenance.

g. Cranes, derricks, hoists, hooks, jacks, and slings.

37–3. Preliminary Considerations

The project definition phase is the most critical aspect of new or refurbished elevator design. There are requirements that overlap or envelop other life safety requirements and other design discipline areas. The project must holistically address not only the immediate code requirements for the elevator but also its integration in the building and its life safety function, along with meeting multi-discipline design and code requirements.

37–4. Assessment

For each powerhouse, the following preliminary considerations should precede design and specification development:

a. For new facilities, collaboration with the building architect and the fire protection, structural, and electrical designers is essential. Elevator equipment must be designed to fit within the structure and meet proposed personnel and equipment loads in all designated areas and elevations of the powerhouse.

b. For existing facilities requiring new or refurbished elevators, project scope determines the level of assessment activities. The outline below provides general activities required for assessment:

(1) Obtain existing design and/or construction documents. Review design assumptions, calculations, shop drawings, commissioning/certification tests, and maintenance records.

(2) Conduct a site investigation to validate the existing equipment installation and observe operation and function.

(3) Meet with all stakeholders to clearly define project scope. Include all designers and all on-site District, Division, and contractor personnel.

c. For existing facilities where design personnel are unqualified or unavailable for assessment, the assistance of a commercial elevator assessment and testing company may be used.

37–5. Engineering and Design

a. General.

(1) All elevator replacement or rehabilitation work performed in powerhouses and pump stations should be evaluated to this section, the latest relevant DoD UFCs, and safety codes.

(2) Elevators typically travel 100 to 200 ft per minute or between 1.14 and 2.27 miles per hour for buildings 10 stories or less.

(3) Nearly every original powerhouse elevator used relay-based control as opposed to modern PLCs. All I/O functions of the PLCs can be monitored and diagnosed using LED indications or an optional human-interface diagnostic tool. The relay-based controls require a higher level of electrical circuit knowledge and thus are harder to troubleshoot and repair.

b. Elevator Inspection. Only experienced personnel should conduct elevator inspections. State-certified inspectors and state-certified contractor inspectors may provide inspection and testing services. Inspection reports should identify safety and maintenance deficiencies useful for facility managers as well as personnel involved in replacing and refurbishing elevators.

c. Elevator Procurement. Elevator procurement is executed and managed solely by the federal Government for DoD facilities. State and local participation or approvals for the design, construction, and testing of federally procured elevators is not required.

d. Submittals. 100 percent technically complete design submittals for new and refurbished elevators are not encouraged due to the specialized equipment and code complexity. Designs should be composed of a mix of detailed and performance requirements. Primary design information includes elevator classification(s) and type(s), equipment room(s) and location(s), car landing elevations, speed, capacity requirements, hoistway envelope dimensions, and controls, including integration with building life safety features and any fire alarm and detection systems.

e. Design Codes. The ASME has published a safety code for elevators since 1921 and serves as the primary elevator code. DoD has established a UFC for elevators that exclusively uses ASME code as basis. EM 385-1-1 includes elevators as well.

(1) *New Elevators*. New elevators require compliance with UFC 3-490-6, ASME A17.1, and UFC 3-600-01.

(2) *Existing Elevators*. Existing elevators require compliance with UFC 3-490-6, ASME A17.3, and UFC 3-600-01. ASME code covers retroactive requirements for existing elevators and establishes minimum standards for all elevator equipment regardless of the installation date. ASME code accounts for the existing building structural conditions that limit the feasibility of bringing elevators up to current ASME A17.1 requirements. ASME code requires that maintenance, repair, and replacements need to conform to the ASME code only at the time of the original installation. However, alteration of the elevator is required to conform to the ASME code at the time of the alteration. New additions to the ASME code are issued approximately every 3 years, along with intermediate supplements issued as needed.

(3) *ASME Code Definitions*.

(a) Alteration: “any change to equipment, including its parts, components, and/or subsystems, other than maintenance, repair, or replacement.”

(b) Maintenance: “a process of routine examination, lubrication, cleaning, and adjustment of parts, components, and/or subsystems for the purpose of ensuring performance in accordance with the applicable Code requirements.”

(c) Repair: “reconditioning or renewal of parts, components, and/or subsystems necessary to keep equipment in accordance with applicable Code requirements.”

(d) Replacement: “The substitution of a device or component and/or subsystems, in its entirety, with a unit that is basically the same as the original for the purpose of ensuring performance in accordance with applicable Code requirements.”

(4) *Elevator Inspection, Testing, Handbooks, and Safety*. Regarding inspection and testing, ASME A17.2 contains recommended inspection and testing procedures for electric and hydraulic elevators, escalators, and moving walks.

(5) *Inspector Requirements*. ASME QEI-1 establishes the requirements for the qualification, duties, and responsibilities of inspectors and inspection supervisors engaged in inspection and testing.

(6) *Handbooks*. ASME A17.1 Handbook and ASME A17.1 Interpretations provides assistance in understanding ASME code requirements and rules.

(7) *Safety*. ASME A17.4 establishes procedures for the safe evacuation of passengers from stalled elevators.

f. Authority Having Jurisdiction. USACE, as the agency regulatory authority, is the AHJ for federally operated DoD facilities. The AHJ is responsible for enforcing all relevant code(s) and includes the construction, installation, operation, testing, inspection, maintenance, alteration, and repair of elevators. State and local officials may not serve as the AHJ on DoD operated facilities unless a legal agreement transfers AHJ authority.

Chapter 38
Corrosion Mitigation Considerations

38–1. General

This chapter supplements recommendations on corrosion control from the preceding chapters.

a. Corrosion is a significant and expensive problem. The conditions required for corrosion are the presence of an anode, a cathode, and a conducting path between the anode and cathode, provided either by an electrolyte that can conduct ions, or by intimate contact directly between anode and cathode. The presence of corrosion stimulators, such as oxygen or chlorides, contribute to a more rapid attack.

b. Hydropower engineers typically employ coatings, sacrificial anodes, and material choices to mitigate corrosion. Impressed current-type cathodic protection systems are not commonly used to protect the equipment in the powerhouse and that is covered by this manual. A common scenario of concern is a submerged carbon steel structure in the vicinity of submerged stainless steel, such as an emergency-closure intake gate with stainless-steel rollers.

c. Corrosion engineering is its own specialty. The final detailed design for a cathodic protection system for critical components (such as emergency-closure gates) should be completed by a Professional Engineer (PE) with a minimum of 5 years of specific corrosion-control experience and training or by a corrosion specialist or cathodic protection specialist certified by Association for Materials Protection and Performance (AMPP) International. Typically, a construction contractor subcontracts cathodic protection work to a specialized AMPP-certified corrosion expert. Preliminary calculations, such as to estimate the total weight that anodes add to a gate, and to confirm feasibility of the desired density of protective current from the anodes (for example, 4–7 mA/ft^2), are performed by the Government during development of plans and specifications.

38–2. References and Resources

a. UFC 3-570-01.

b. EM 1110-2-2704.

c. EM 1110-2-3400.

d. Mobile District maintains the Corrosion Control and Cathodic Protection Systems TCX. While it is not mandatory to involve this TCX for all projects involving cathodic protection, this is recommended whenever possible. If the TCX will be involved in a project, coordination should start early in the design phase.

e. The Construction Engineering Research Laboratory (CERL) within the ERDC maintains the USACE Paint Technology Center of Expertise. This TCX is the proponent of the relevant UFGSs, including UFGS 09 97 02, which is frequently used for hydropower equipment.

f. UFGSs for cathodic protection are organized within Division 26 – Electrical. An example is UFGS 26 42 13.

g. The AMPP is a professional organization combining the previous Society for Protective Coatings (SSPC) and NACE International (originally the National Association of Corrosion Engineers). Informally, “SSPC” and “NACE” are still commonly used.

38–3. Design Considerations

a. General. To control corrosion, it is necessary to eliminate one or more of the requirements for corrosion.

b. Goal. Once safety and functionality requirements are met, the goal of corrosion mitigation is to achieve the lowest life cycle cost for the equipment being protected. As prices of labor and materials change and information on the performance of materials becomes available, past experience and life cycle cost data should be reviewed to determine whether this goal is being achieved. For example, bare steel with an appropriate corrosion allowance might provide a full design life at a lower cost than a coated structure.

c. Environment. It is sometimes useful to consider the possibility of altering the environment in which the equipment will be placed. The cost of protecting equipment from its environment can be changed significantly. For example, consider whether the equipment can be placed indoors rather than outdoors. Once the environment is set, select appropriate materials to withstand the environment or means of excluding fluids from a metallic structure, such as coatings.

d. Design Geometry. Equipment in wet or immersed environments should avoid designs that allow water to be trapped or that make coating difficult, such as sharp edges, crevices, or numerous bolts.

e. Material Selection. In general, EMs and UFGSs provide conservative advice. The water quality or temperature ranges for some power plants may be more or less severe than average, such that deviations from standard guidance are warranted. For example, local water quality might result in severe consequences of placing dissimilar metals in contact where moisture is present. This should be documented in the design documentation report (DDR). Also consider using non-metallic materials.

f. Protecting Metals. Methods of protection for various environments are indicated below. Actual choices should consider the aggressiveness of the environment (such as a water analysis).

(1) *Immersed*. This category applies to structures and equipment periodically or permanently immersed in water and the interior of water piping systems. The methods for protection include using corrosion-resistant metals, applying metallic and non-metallic coatings, providing dielectric isolators between dissimilar metals, and cathodic protection. Closed-loop piping system systems may also employ chemical treatment, but environmental considerations such as disposal of the fluid must also be weighed.

(2) *Embedded*. Methods of protection are the same as for the immersed category. Exterior surfaces of metals encased in concrete, except at transitions between concrete and atmosphere, may not require any protection. Interior surfaces and exterior surfaces of structures buried in soils should be protected.

(3) *Atmospheric*. The choice is usually made between corrosion-resistant metals and alloys or using coatings to protect ferrous materials in exterior exposures. Similar choices are used for interior exposures, dehumidification, and insulation.

g. Galvanic Couples. Where galvanic coupling of dissimilar metals is expected to cause corrosion problems, the choices for prevention include dielectric isolation, coating of both metals, or cathodic protection. Unintentional galvanic couples such as ferrous underground or immersed piping, which is metallically connected to the copper station ground mat or coated steel piping adjacent to stainless-steel tracks in an intake gate slot, also creates problems. In these latter cases, the relative area of noble metal is high due to the coating on the steel, and pitting can be rapid.

h. *Future Maintenance*. Give consideration to how corrosion damage may be mitigated by renewing coatings, anodes, and components. Implementing appropriate corrosion mitigation can reduce overall life cycle costs by reducing maintenance and prolonging the usable service life of the equipment or structure. Additional considerations include whether painting will be performed on site or in a shop, the difficulty and safety of access for painting if on site, and the cost and scheduling of outages to perform maintenance.

i. *Safety and Critical Items*. Items that involve life safety and require regular inspection, such as pressure vessels or wire ropes, should be designed for easy access to make such inspections or tests.

j. *Miscellaneous Factors*. Other factors that affect corrosion and require design consideration are temperature, velocity, chemical concentration, contamination, and absence of film-forming properties in some waters.

k. *Magnesium Anodes*. Magnesium anodes in direct contact with a painted surface can cause the paint coating to rupture due to hydrogen gas being created at the cathode/surface. Often, magnesium anodes are partially covered with a dielectric coating (such as “plastisol”) to prevent direct contact with the structure. (This coating can also serve to extend the design life of an individual anode by exposing less of the surface area to the water.) Take care to not create crevice corrosion under the anodes, however. Consider either applying epoxy to protect the crevices under the anodes, or (if clearances allow) having the coated magnesium anodes spaced away from the structure sufficiently to allow protective current to reach the area under the anode.

38–4. Corrosion Mitigation for Hydraulic Steel Structures

a. Special care should be taken with turbine intake gates and other equipment falling under the purview of HSS. See ER 1110-2-8157 and EM 1110-2-2107.

(1) Drain holes should be provided in horizontal members and where water and debris are likely to accumulate.

(2) Welded joints should be sealed by welding the entire joint, to include wrapping welds. Seal welds should be the same size as the adjacent weld or according to AWS minimum weld sizes, whichever is greater.

b. The primary means of corrosion mitigation for HSS is applying the appropriate protective coating according to EM 1110-2-3400 and UFGS 09 97 02.

(1) For HSS in freshwater subject to immersion, the vinyl coating system 5-E-Z is most common. The 5-E-Z system has superior barrier, impact, and abrasion resistance characteristics. The 5-E-Z should not be used in sea water or an environment with high chloride concentration. For these, a coal tar epoxy (System 6-A-Z) or epoxy coating with zinc-rich primer (System 21-A-Z) should be considered.

(2) Storage of gates and bulkheads that keep them dry and out of direct sunlight can prolong the service life of the coating system and the structure.

(3) For gates and bulkheads subject to immersion but not abrasion, other coating systems may be considered. Consult the USACE Paint Technology Center when specifying a coating system other than the 5-E-Z vinyl system.

c. Cathodic protection anodes are typically placed near stainless-steel components on gates. For intake gates, this tends to be at the ends of the gate where the stainless-steel rollers and tracks are located. The center of the gates typically have fewer anodes as there typically are no stainless steels within these areas. The center span of the gates rely more on vinyl paint to provide corrosion protection. Maintaining the paint system is essential to keeping the steel structure protected from corrosion.

(1) EM 1110-2-2704 states that bare-edged magnesium anodes are not to be used for any upstream gate or leaf surface.

(2) Anodes bolted directly to the skin plate or within the sealing plane can result in leakage paths through the structure and should be avoided. Exceptions are structural splicing connections joining gate sections together, in which rubber gaskets should be used to reduce the likelihood of leakage.

(3) EM 1110-2-2107 specifically states that “Connections for components that require removal for routine maintenance such as … cathodic protection sacrificial components … should not be welded.” Best practice is to bolt cathodic protection anodes to the structure. However, bolting directly to the skin plate or other elements in the sealing plane is not recommended. Instead, a mounting element (plate, angle, stud, etc.) should be welded to the structure that allows the bolted connection of the anode. This eliminates a leakage path through the sealing plane. The Engineer of Record should approve weld details to verify it meets EM 1110-2-2107, especially if welding to a fracture-critical member, and confirm mounting elements are located in low-risk areas.

(4) Care should be taken when using cathodic protection in combination with vinyl coatings as the cathodic protection system can result in cathodic disbondment (such as blistering) of the coating adjacent to the anodes. Dielectric coatings should be used to reduce the risk of blistering. Consult the Corrosion Control and Cathodic Protection Systems TCX when designing cathodic protection systems.

38–5. Rehabilitation Considerations

a. Initial/feasibility cathodic protection calculations require several inputs:

(1) Material, geometry, and design life of the equipment, design life of the anodes (typically ~20 years), and portion of design life spent submerged.

(2) Present-day local water resistivity data, preferably over a period of a full year to capture seasonal changes. Note that water chemistry can change over time, and historic numbers may no longer be accurate.

(3) Confirmation that desired anode type and geometry is available, in particular when high-potential magnesium anodes are desired due to high-resistivity fresh water. Different types and shapes of anodes might be used in different areas of a structure (for example, compartments versus skin plate).

b. Specify that anodes be distributed so as not to interfere with how the gate hangs vertically in either plane. Anodes that provide uniform potential are already likely to be symmetrically placed with respect to the gate center of gravity and geometry, which is critical so that the gate does not get racked in the slot. However, changes in the center of gravity of the free-hanging gate can impact alignment and pose problems, such as difficulty lowering the gate into a slot.

c. Consider specifying the sequence of mounting bolt installation onto the gate or other structure to be cathodically protected, so that construction contractors not accustomed to cathodic protection are aware of the schedule requirements (for example, weld mounting bolts, drill and tap, protect all threads prior to painting, then install anodes, then verify electrical continuity, then apply insulating mastic coating to the connections). Specify that anode bolting connections are not lubricated, for better electrical connections.

d. Consider specifying and scheduling a second site visit for the AMPP-certified corrosion expert to verify cathodic protection is functioning after approximately a month of submergence, with any poor connections to be corrected and re-verified by the Contractor.

e. Consider requiring that the AMPP-certified corrosion expert approve the coating system to ensure its compatibility with the cathodic protection system. This can help avoid conflicting claims regarding the cause of any malfunctions during the warranty period.

f. Anodes that remain well attached for their full design life will probably be replaced all at once under a contract. For anodes that might become damaged in the meantime, consider whether to specify spare anodes, prepared for long-term storage, and installation instructions.

Chapter 39
Maintenance Shop

39–1. Preface

a. The content of this chapter is applicable only to new powerhouse construction, but is included with this revision of the manual as a reference and to provide insight on how the powerhouses were originally designed and constructed. It may also be used in the event a new powerhouse is constructed.

b. The operation, maintenance, and equipment configuration of existing maintenance shops is the responsibility of the operating Project and District Operations Division. The configuration and equipment should be configured to the current needs of the operating Project.

c. The HDC should be consulted if there are required modifications or improvements related to the electrical distribution system, powerhouse compressed air system, water supply systems, and fire protection systems.

39–2. General

a. Most powerhouses were constructed with shops for preventative maintenance and to provide moderate repair capability. However, shops were omitted where there was an adequately equipped project shop outside the powerhouse at a nearby location, or where a small powerhouse was located close enough to an adjoining project with an adequate maintenance facility to permit practical joint use.

b. The intent was that each powerhouse had the capability to take care of average work promptly and efficiently. Capability for all possible required repairs is not intended even in the most well-equipped shop as factory replacements or contract work can be more practical.

39–3. Shop Room

a. *Location*. A location close to the erection area and on the same elevation is preferred. Convenient transfer of material, equipment, and parts from the powerhouse bridge crane and trucks to the shop transporting facility should also be planned. The location should permit the shop to be enclosed and provide a large access door permitting free movement of material from the transporting facility.

b. *Area*. The shop area should provide adequate space for the planned equipment with consideration for the size and configuration of pieces to be worked on; space for dismantling and reassembly; and space for safe, efficient movement of personnel. An area of about 800–1,000 sq ft (74–93 square meters) should be the minimum area for a reasonably equipped shop in a small plant. An area of 1,600–1,800 sq ft (149–167 square meters) may be justified for a large multi-unit plant or a central facility serving several small projects. An adjoining area for a lockable tool and storage room should be available and should be a minimum of 100 sq ft (9 square meters).

39–4. Equipment Selection

a. *Factors*. Factors affecting the selection of equipment include the following:

(1) Size of plant (volume of work).

(2) Physical size of parts to be repaired.

(3) Location of plant (access to other Government or commercial facilities).
(4) Equipment cost (probable usage to justify investment).
(5) Available shop space.
(6) Personnel planning (type of equipment to be consistent with personnel skills).
(7) Equipment guides.

b. For small to medium powerhouses with well-equipped commercial or Government shops available 1–4 hours travel time away, the following equipment, or equivalent, should be planned:

(1) 2-ton floor crane.
(2) 300-amp welder.
(3) Welding hood and exhaust fan.
(4) 2-in. (51-mm) pipe threading machine (portable).
(5) 6 x 6-in. (152 x 152-mm) power hacksaw or bandsaw.
(6) 60-ton press.
(7) 10-in. (254-mm) pedestal grinder.
(8) 15-in. (381-mm) floor-mounted drill press.
(9) 12–14-in. (305–356-mm) lathe.

c. For large multiunit powerhouses, shops serving several projects, or for smaller powerhouses in remote locations, the following equipment, or equivalent, should be planned:

(1) 2-ton floor crane. A 3-ton bridge crane can be justified for heavy work volume shops.
(2) 300-amp welder.
(3) Welding hood and exhaust fan.
(4) 2-in. (51-mm) pipe threading machine (portable).
(5) 6 x 6-in. (152 x 152-mm) power hacksaw or bandsaw.
(6) 60-ton press.
(7) 12-in. (305-mm) pedestal grinder.
(8) 8-in. (203-mm) bench grinder.
(9) 3-ft (914-mm) radial drill press.
(10) 12-in. (305-mm) bench-mounted drill press.
(11) 18-in. (457-mm) engine lathe.
(12) 10-in. (254-mm) bench lathe.
(13) 10 × 40-in. (254 x 1016-mm) milling machine.

39–5. Shop Layout

Machines should be located to provide good access for placing parts and materials in each machine. Repair shops normally require more free area around machines than production shops where specific operations can be scheduled. Space for two to four 3 x 10-ft (0.9 x 3-m) work benches are usually required. Open floor area for assembly, disassembly, and short-term storage of parts is desirable. The welding area, burning area, and grinders should be located away from precision machine work and assembly areas. Power should be provided for all fixed machines to be installed, and for portable tools at benches and assembly areas.

Appendix A
References

Section I

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Standard Specification for Hubless Cast Iron Soil Pipe and Fittings for Sanitary and Storm Drain, Waste, and Vent Piping Applications (Available at https://www.cispi.org/wp-content/uploads/2019/02/CISPI-301-18_3262018.pdf)

CMAA (Crane Manufacturers Association of America) 70
Top Running Bridge and Gantry Type Multiple Girder Electric Overhead Traveling Cranes (Available at https://www.mhi.org/cmaa/specifications)

CSA (Canadian Standards Association) C22.2 Number 0.3-01
Test Methods for Electrical Wires and Cables
(Available at https://www.csagroup.org/store/)

EPRI (Electric Power Research Institute)– EL-5036
Volume 4 - Wire and Cable
Volume 5 - Grounding and Lightning Protection
Volume 9 - DC Distribution System
Volume 13 - Power Plant Electrical Reference Series, Volume 13: Communications
(Available at https://www.epri.com/)

ICC (International Code Council)
International Plumbing Code (IPC) (Available at https://www.iccsafe.org/content/international-plumbing-code-ipc-home-page/)

ICEA (Insulated Cable Engineers Association)
All ICEA standards can be found at https://webstore.ansi.org/standards/.

ICEA S-73-532/National Electrical Manufacturers Association (NEMA) WC 57
Standard for Control, Thermocouple, Extension, and Instrumentation Cables

ICEA S-93-639/NEMA WC 74
5-46 kV Shielded Power Cable for Use in the Transmission and Distribution of Electric Energy

ICEA S-95-658/NEMA WC 70
Power Cables Rated 2000 Volts or Less for the Distribution of Electrical Energy

ICEA S-116-732/NEMA WC 66
Standard for Category 6 And 6a, 100 Ohm, Individually Unshielded Twisted Pairs, Indoor Cables (With Or Without An Overall Shield) For Use In LAN Communication Wiring Systems

IEC (International Electrotechnical Commission)
All IEC standards are available at https://iec.ch/homepage.

IEC 60076-15
Power Transformers – Part 15: Gas-filled power transformers

IEC 60870-6-503
Telecontrol Equipment and Systems – Part 6-503: Telecontrol protocols compatible with ISO standards and ITU-T recommendations – TASE.2 Services and protocol

IEC 61131-1
Programmable Controllers – Part 3: Programming Languages

IEC 61131-3
Programming Industrial Automation Systems

IEC 61869-1
Instrument transformers – Part 1: General requirements

IEC 61869-2
Instrument transformers – Part 2: Additional requirements for current transformers

IEC 62271-201
High-voltage switchgear and control gear – Part 201: AC solid-insulation enclosed switchgear and control gear for rated voltages above 1 kV and up to and including 52 kV

IEC/IEEE 62271-37-013
International Standard for High-voltage switchgear and controlgear – Part 37-013: Alternating current generator circuit breakers

IEEE (Institute of Electrical and Electronics Engineers)
All IEEE standards are available at https://standards.ieee.org/.

IEEE 4
High-Voltage Testing Techniques

IEEE 43
Recommended Practice for Testing Insulation Resistance of Rotating Machinery

IEEE 80
Guide for Safety in AC Substation Grounding

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

IEEE 95
Recommended Practice for Insulation Testing of AC Electric Machinery (2300 V and Above) With High Direct Voltage

IEEE 115
Guide for Test Procedures for Synchronous Machines Including Acceptance and Performance Testing and Parameter Determination for Dynamic Analysis

IEEE 125
Recommended Practice for Preparation of Equipment Specifications for Speed-Governing of Hydraulic Turbines Intended to Drive Electric Generators

IEEE 142
Grounding of Industrial and Commercial Power Systems

IEEE 242
Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems

IEEE 367
Recommended Practice for Determining the Electric Power Station Ground Potential Rise and Induced Voltage from a Power Fault

IEEE 399
Recommended Practice for Industrial and Commercial Power Systems Analysis

IEEE 421.1
IEEE Standard Definitions for Excitation Systems for Synchronous Machines

IEEE 421.2
IEEE Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems

IEEE 421.3
IEEE Standard for High-Potential Test Requirements for Excitation Systems for Synchronous Machines

IEEE 421.4
IEEE Guide for the Preparation of Excitation System Specifications

IEEE 421.5
IEEE Recommended Practice for Excitation System Models for Power System Stability Studies

IEEE 421.6
IEEE Recommended Practice for the Specification and Design of Field Discharge Equipment for Synchronous Machines

IEEE 422
Guide for the Design of Cable Raceway Systems for Electric Generating Facilities

IEEE 450
Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications

IEEE 484
Recommended Practice for Installation Design and Installation of Vented Lead-Acid Batteries for Stationary Applications

IEEE 485
Recommended Practice for Sizing Lead-Acid Batteries for Stationary Applications

IEEE 492
IEEE Guide for the Operation and Maintenance of Hydro Generators

IEEE 605
Guide for Bus Design in Air Insulated Substations

IEEE 666
Design Guide for Electric Power Service Systems for Generating Stations

IEEE 693
Recommended Practice for Seismic Design of Substations

IEEE 837
Standard for Qualifying Permanent Connections Used in Substation Grounding

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

IEEE 979
Guide for Substation Fire Protection

IEEE 980
Guide for Containment and Control of Oil Spills in Substations

IEEE 1010
IEEE Guide for Control of Hydroelectric Powerplants

IEEE 1147
IEEE Guide for the Rehabilitation of Hydroelectric Power Plants

IEEE 1202
Standard for Flame-Propagation Testing of Wire and Cable

IEEE 1207
Guide for the Application of Turbine Governing Systems for Hydroelectric Generating Units

IEEE 1249
IEEE Guide for Computer-based Control for Hydroelectric Power Plant Automation

IEEE 1491
Guide for Selection and Use of Battery Monitoring Equipment in Stationary Applications

IEEE 1584
Guide for Performing Arc-Flash Hazard Calculations

IEEE C2
National Electrical Safety Code

IEEE C37.04
Standard for Ratings and Requirements for AC High-Voltage Circuit Breakers with Rated Maximum Voltage Above 1000 V

IEEE C37.06
Standard for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis-Preferred Ratings and Related Required Capabilities for Voltages Above 1000 V

IEEE C37.09
Standard Test Procedures for AC High-Voltage Circuit Breakers with Rated Maximum Voltage Above 1000 V

IEEE C37.010
Guide for AC High-Voltage Circuit Breakers > 1000 Vac Rated on a Symmetrical Current Basis

IEEE C37.011
Application Guide for Transient Recovery Voltage for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis

IEEE C37.013
Standard for AC High-Voltage Generator Circuit Breakers Rated on a Symmetrical Current Basis (superseded)

IEEE C37.017
Standard for Bushings for High-Voltage (over 1000 V [ac]) Circuit Breakers and Gas-Insulated Switchgear

IEEE C37.2
Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations

IEEE C37.13
Standard for Low-Voltage AC Power Circuit Breakers Used in Enclosures

IEEE C37.20.1
Standard for Metal-Enclosed Low-Voltage (1000 Vac and below, 3200VDC and below) Power Circuit Breaker Switchgear

IEEE C37.20.2
Standard for Metal-Clad Switchgear

IEEE C37.20.3
Standard for Metal-Enclosed Interrupter Switchgear

IEEE C37.23
Standard for Metal-Enclosed Bus

IEEE C37.30.1
Standard Requirements for AC High-Voltage Air Switches Rated Above 1000 V

IEEE C37.30.2
Guide for Wind-Loading Evaluation of High-Voltage (>1000 V) Air-Break Switches

IEEE C37.32a
American National Standard for High Voltage Switches, Bus Supports, and Accessories Schedules of Preferred Ratings, Construction Guidelines, and Specifications

IEEE C37.59
Standard for Requirements for Conversion of Power Switchgear Equipment

IEEE C37.91
Guide for Protecting Power Transformers

IEEE C37.101
Guide for Generator Ground Protection

IEEE C37.102
Guide for AC Generator Protection

IEEE C37.110
Guide for the Application of Current Transformers Used for Protective Relaying Purposes

IEEE C37.113
Guide for Protective Relay Applications to Transmission Lines

IEEE C37.234
Guide for Protective Relay Applications to Power System Buses

IEEE C50.12
Salient Pole 50 Hz and 60 Hz Synchronous Generators and Generator/Motors for Hydraulic Turbine Applications Rated 5 MVA and Above

IEEE C50.13
Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above

IEEE C57.12
Standard for General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers

IEEE C57.12.91
Test Code for Dry-Type Distribution and Power Transformers

IEEE C57.12.10
Requirements for Liquid-Immersed Power Transformers

IEEE C57.13
Standard Requirements for Instrument Transformers

IEEE C57.13.3
Guide for Grounding of Instrument Transformer Secondary Circuits and Cases

IEEE C57.19.01
Performance Characteristics and Dimensions for Power Transformer and Reactor Bushings

IEEE C57.19.04
Performance Characteristics and Dimensions for High-Current Power Transformer Bushings with Rated Continuous Current in Excess of 5000 A in Bus Enclosures

IEEE C57.92
Guide for Loading Mineral-Oil-Immersed Power Transformers up to and Including 100 MVA with 55 °C or 65 °C Average Winding Rise

IEEE C57.104
Guide for the Interpretation of Gases Generated in Mineral Oil-Immersed Transformers

IEEE C57.106
Guide for Acceptance and Maintenance of Insulating Mineral Oil in Electrical Equipment

IEEE C57.116
Guide for Transformers Directly Connected to Generators

IEEE C57.120
Guide for Loss Evaluation of Distribution and Power Transformers and Reactors

IEEE C57.147
Guide for Acceptance and Maintenance of Natural Ester Insulating Liquid in Transformers

IEEE C62.11
Standard for Metal-Oxide Surge Arresters for AC Power Circuits (>1 kV)

IEEE C62.22
Guide for the Application of Metal-Oxide Surge Arresters for Alternating-Current Systems

IEEE C62.23
Application Guide for Surge Protection of Electric Generating Plants

IEEE C62.82.1
Standard for Insulation Coordination – Definitions, Principles, and Rules

IEEE C62.92.2
Guide for the Application of Neutral Grounding in Electrical Utility Systems, Part II – Synchronous Generator Systems

IES (Illuminating Engineering Society) G-2
Guideline for the Application of General Illumination ("White") Light-Emitting Diode (LED) Technologies (Available at https://www.ies.org/standards/)

ISA (International Society of Automation) 101.01
Human Machine Interfaces for Process Automation Systems
(Available at https://www.isa.org/standards-and-publications)

ISO (International Organization for Standardization)
All ISO standards are available at https://www.iso.org/standards.html.

ISO 7919-5
2005 – Mechanical Vibration – Evaluation of Machine Vibration by Measurements on Non-Rotating Shafts, Part 5: Machine Sets in Hydraulic Power Generating and Pumping Plants

ISO 9223
Corrosion of Metals and Alloys – Corrosivity of Atmospheres – Classification, Determination and Estimation

ISO 10816-1
Mechanical Vibration – Evaluation of Machine Vibration by Measurements on Non-Rotating Shafts, Part 1: General Guidelines

ISO 10816-3
Mechanical Vibration – Evaluation of Machine Vibration by Measurements on Non-Rotating Shafts, Part 3: Industrial Machines with Nominal Power Above 15kW and Nominal Speeds Between 120r/min and 15,000 r/min When Measured In Situ

ISO 10816-5
Mechanical Vibration – Evaluation of Machine Vibration by Measurements on Non-Rotating Shafts, Part 5: Machine Sets in Hydraulic Power Generating and Pumping Plants

ISO 10816-7
Mechanical Vibration – Evaluation of Machine Vibration by Measurements on Non-Rotating Shafts, Part 7: Rotodynamic Pumps for Industrial Application, Including Measurements on Rotating Shafts

ISO 20816-5
Mechanical Vibration – Evaluation of Machine Vibration by Measurements on Non-Rotating Shafts, Part 5: Machine Sets in Hydraulic Power Generating and Pumping Plants. 2018.

Marks' Standard Handbook for Mechanical Engineers Wire Rope User's Manual
Sadegh, A., and Worek, W. 2017. Marks' Standard Handbook for Mechanical Engineers. McGraw Hill.

Mechanical Engineers' Handbook
Carmichael, C. 1950, 4th edition 2015. *Mechanical Engineers' Handbook.* John Wiley & Sons, Inc. (available at https://www.wiley.com/en-br/Mechanical+Engineers%27+Handbook%2C+4+Volume+Set%2C+4th+Edition-p-9781118118993)

MSS (Manufacturers Standardization Society)
All MSS standards are available at https://msshq.org/page/ActiveStandards

MSS SP-58
Pipe Hangers and Supports

MSS SP-83
Class 3000 and 6000 Pipe Unions, Socket Welding and Threaded (Carbon Steel, Alloy Steel, Stainless Steels, and Nickel Alloys)

NEMA (National Electrical Manufacturers Association)
All NEMA standards are available at https://www.nema.org/standards.

NEMA C80.1
Electrical Rigid Steel Conduit

NEMA ICS 8
Application Guide for Industrial Control and Systems Crane and Hoist Controllers

NEMA MG 1
Motors and Generators

NEMA PE 1
Uninterruptible Power Systems (UPS) – Specification and Performance Verification

NEMA PE 5
Utility Type Battery Chargers

NEMA VE 1
Metal Cable Tray Systems

NEMA VE 2
Cable Tray Installation Guidelines

NEMA WD 6
Wiring Devices – Dimensional Specifications

NERC (North American Electric Reliability Corporation) MOD-0261
Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions. 2014.
(Available at https://www.nerc.com/pa/Stand/Reliability%20Standards/MOD-026-1.pdf)

NERC Standard PRC-005-2
Protection System Maintenance
(Available at https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-005-2.pdf)

NETA – ATS
Standard for Acceptance Testing Specifications for Electrical Power Equipment and Systems (Available at https://www.netaworld.org/standards)

NETA – MTS
Standard for Maintenance Testing Specifications for Electrical Power Equipment and Systems (Available at https://www.netaworld.org/standards)

NFPA (National Fire Protection Association)
All NFPA standards are available at https://www.nfpa.org/Codes-and-Standards/All-Codes-and-Standards/List-of-Codes-and-Standards.

NFPA 1
Fire Code, Chapter 52 Stationary Storage Battery Systems

NFPA 10
Standard for Portable Fire Extinguishers

NFPA 12
Standard on Carbon Dioxide Extinguishing Systems

NFPA 30
Flammable and Combustible Liquids Code

NFPA 33
Standard for Spray Application Using Flammable or Combustible Materials

NFPA 70
National Electrical Code (NEC)

NFPA 70E
Standard for Electrical Safety in the Workplace

NFPA 91
Standard for Exhaust Systems for Air Conveying of Vapors, Gases, Mists, and Particulate Solids

NFPA 92
Standard for Smoke Control Systems

NFPA 101
Life Safety Code

NFPA 850
Recommended Practice for Fire Protection for Electric Generating Plants and High-Voltage Direct Current Converter Stations

Roark's Formulas for Stress and Strain
Budynas R., Sadegh, A., and Young, W. 2012. *Roark's Formulas for Stress and Strain*. McGraw Hill; 8th edition.

Runaway Speed of Kaplan Turbines
G.H. Voaden. 1952. S. Morgan Smith Co.

UFC (Unified Facilities Criteria)
All UFCs are available at https://www.wbdg.org/ffc/dod/unified-facilities-criteria-ufc.

UFC 1-200-01
DoD Building Code

UFC 3-230-01
Water Storage and Distribution

UFC 3-230-03
Water Treatment

UFC 3-400-02
Engineering Weather Data

UFC 3-410-01
Heating, Ventilating, and Air Conditioning Systems

UFC 3-410-04
Industrial Ventilation

UFC 3-420-01
Plumbing Systems

UFC 3-420-02FA
Compressed Air

UFC 3-440-01
Facility-Scale Renewable Energy Systems

UFC 3-490-06
Elevators

UFC 3-520-05
Stationary Battery Areas

UFC 3-530-01
Interior and Exterior Lighting Systems and Controls

UFC 3-570-01
Cathodic Protection

UFC 3-600-01
Fire Protection Engineering for Facilities

UFC 3-601-02
Fire Protection Systems Inspection, Testing, and Maintenance

UFC 4-021-01
Design and O&M Mass Notification Systems

UFGS (Unified Facilities Guide Specifications)
All UFGS are available at https://www.wbdg.org/ffc/dod/unified-facilities-guide-specifications-ufgs.

UFGS 09 97 02
Painting, Hydraulic Structures

UFGS 09 97 13.17
Three Coat Epoxy Interior Coating of Welded Steel Petroleum Fuel Tanks

UFGS 22 00 00
Plumbing, General Purpose

UFGS 26 42 13
Galvanic (Sacrificial) Anode Cathodic Protection (GACP) System

UFGS 35 05 40.14
Hydraulic Power Systems

UFGS 35 05 40.14 10
Hydraulic Power Systems for Civil Works Structures

UFGS 40 05 13
Pipelines, Liquid Process Piping

UFGS 40 60 00
Process Control

UL (Underwriters Laboratories)
All UL standards can be found at https://ulstandards.ul.com/.

UL 96A
Standard for Installation Requirements for Lightning Protection Systems

UL 142
Steel Above Ground Tanks for Flammable and Combustible Liquids

UL 467
Grounding and Bonding Equipment

UL 498
Attachment Plugs and Receptacles

UL 514A
Metallic Outlet Boxes

UL 891
Switchboards

UL 1682
Plugs, Receptacles, and Cable Connectors of the Pin and Sleeve Type

UL 1685
Vertical-Tray Fire-Propagation and Smoke-Release Test for Electrical and Optical-Fiber Cables

UL 1686
Standard for Pin and Sleeve Configurations

UL 2686
Outline of Investigation for Switch-Rated Plugs and Receptacles

Wire Rope Users Manual
Wire Rope Technical Board. (Available at https://www.wireropetechnicalboard.org/)

Section II
Prescribed Forms

This section contains no entries.