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An Introduction to Generator Voltage, Station Service and Control Systems for Hydroelectric Power Plants

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1. GENERATOR-VOLTAGE SYSTEM

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

1.2 GENERATOR LEADS

1.2.1 GENERAL. The term "generator leads" applies to the circuits between the generator terminals and the low voltage terminals of the GSU transformers. The equipment selected depends upon the distance between the generator and transformer, the capacity of the generator, the type of generator breakers employed, and the economics of the installation. There are two general classes of generator leads: those consisting of metal-enclosed buses and those consisting of medium-voltage cables. The two classes, their advantages, disadvantages, and selection criteria are discussed in the following subparagraphs. b. Metal-enclosed buses. There are three categories of metal-enclosed bus: nonsegregated-phase, segregated phase, and isolated-phase. Each type has specific applications dependent mainly on current rating and type of circuit breaker employed with the bus.

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

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

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

1.3 METAL-ENCLOSED BUS APPLICATION CRITERIA.

1.3.1 FOR MOST MAIN UNIT APPLICATIONS, the metal enclosed form of generator leads is usually preferred, with preference for the isolated-phase type for ratings above 3,000 A. Enclosed buses that pass through walls or floors should be arranged so as to permit the removal of housings to inspect or replace insulators.

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

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

1.3.4 ON ALL ENCLOSED BUS RUNS, requirements for enclosing the connections between the bus and the low voltage bushings of the GSU transformer should be coordinated and responsibilities for scopes of supply clearly defined between transformer supplier and bus supplier. Details of the proposed design of the connector between the GSU transformer bushing terminals and the bus terminal should be evaluated to ensure probability of reliable service life of the connection system.

1.4 INSULATED CABLES.

1.4.1 CABLES MAY BE APPROPRIATE for some small generators or in installations where the GSU transformer is located in the plant's switchyard. In the latter situation, economic and technical evaluations should be made to determine the most practical and cost-effective method to make the interconnection. Cables, if used, should have copper conductors. Acceptable cable types include: (a) Single conductor, ethylene-propylene-rubber (EPR) insulated, with non-PVC jacket. (b) Multi-conductor, ethylene-propylene-rubber (EPR) insulated cables, with aluminum or steel sheath, and non- PVC jacket, in multiple if necessary to obtain capacity. (c) Oil-pipe cable systems.

1.4.2 OIL-FILLED CABLE TERMINATIONS with cables terminated with a conductor lug and a stress cone should be used for terminating oil-pipe cable systems. Cold shrink termination kits should be used for terminating single and multi-conductor EPR cables. Termination devices and kits should meet the requirements of IEEE 48 for Class I terminations.

1.4.3 WHEN CABLES OF ANY TYPE are run in a tunnel, the effect of cable losses should be investigated to determine the safe current-carrying capacity of the cable and the extent of tunnel ventilation required to dissipate the heat generated by these losses. Locations where hot spots may occur, such as risers from the tunnel to equipment or conduit exposed to the sun, should be given full consideration.

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

1.6 INSTRUMENT TRANSFORMERS

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

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

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

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

1.8 EXCITATION SYSTEM POWER POTENTIAL TRANSFORMER. The power potential transformer (PPT) is fed from the generator leads. The PPT is procured as part of the excitation system equipment. The PPT should be a three phase, 60-Hz, self-cooled, ventilated dry type transformer. The PPT is generally tapped at the generator bus with primary current limiting fuses, designed for floor mounting, and with a low-voltage terminal chamber with provisions for terminating the bus or cable from the excitation system power conversion equipment.

1.9 CIRCUIT BREAKERS

1.9.1 GENERAL. The particular switching scheme selected from those described includes the generator voltage and capacity rating, and results from fault studies will determine the type of generator breaker used for switching, together with its continuous current rating and short-circuit current rating. If a “unit” switching scheme is chosen with switching on the high side of the GSU transformer, then criteria regarding high-voltage power circuit breakers are used to select an appropriate breaker. If a generator-voltage switching scheme is selected, then criteria outlined in this paragraph should be used for breaker selection.

1.9.2 GENERATOR-VOLTAGE CIRCUIT BREAKER TYPES.

1.9.2.1 WHEN GENERATOR-VOLTAGE CIRCUIT BREAKERS are required, they are furnished in factory-built steel enclosures in one of three types. Each type of circuit breaker has specific applications dependent on current ratings and short-circuit current ratings. In general, Table 6-1 provides a broad overview of each breaker type and its range of application for generator switching. The three types are as follows: (a) Metal-clad switchgear. Metal-clad switchgear breakers can be used for generator switching on units of up to 45 MVA at 13.8 kV, depending on interrupting duty requirements. Either vacuum interrupters or SF6 interrupting mediums are permitted by the guide specification. (b) Station-type cubicle switchgear. Station-type breakers can be used in generator switching applications on units of approximately 140 MVA. Details of construction are covered in IEEE C37.20.2. For SF6 circuit breakers, the insulating and arc-extinguishing medium is the gas. For indoor equipment, in areas not allowed to reach temperatures at or near freezing, the gas will probably not require heating provisions. However, special care and handling is needed for SF6 gas. (c) In-line isolated-phase bus breakers. For high current, medium-voltage, generator breaker applications, i.e., 15 kV, 6,000 Amp or higher, in-line breakers mounted in the isolated-phase bus system have been employed on high-capacity systems. These breakers employ either SF6 or compressed air insulating and arc extinguishing systems and can incorporate breaker isolating switches in the breaker compartment. This type of breaker requires less space than a station type cubicle breaker but has higher initial cost. It should receive consideration where powerhouse space is at a premium. Technical operating parameters and performance are covered in IEEE C37.013.

1.9.2.2 THE ESSENTIAL FEATURES OF DRAW-OUT METAL-CLAD switchgear and station type cubicle switchgear are covered in IEEE C37.20.2. Essential features of in-line isolated phase bus-type circuit breakers are covered in IEEE C37.013 and C37.23. Specific current and interrupting ratings available at other voltages are summarized in Tables 6-2 and 6-3.

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

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

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

2. STATION SERVICE SYSTEM

2.1 POWER SUPPLY

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

2.1.2 PLANT “BLACK START” CAPABILITY.

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

2.1.2.2 POWER SYSTEM PROBLEMS. (a) There are a number of circumstances that can lead to collapse of all or parts of a bulk power distribution system. Regardless of the circumstances, the triggering event generally leads to regional and subregional mismatch of loads and generation and “islanding” (i.e., plants providing generation to isolated pockets of load). Separation of generation resources from remote loads and “islanding” can cause voltage or frequency excursions that may result in the loss of other generation resources, particularly steam generation, which is more sensitive to frequency excursions than hydroelectric turbine generators. Steam generation is also harder to return to service than hydro generation, so the burden of beginning system restoration is more likely to fall on hydro resources. (b) When a transmission line is removed from service by protective relay action, the power it was carrying will either seek another transmission line route to its load, or be interrupted. If its power is shifted to other transmission lines, those lines can become overloaded and also be removed from service by protective relays. System failures are more likely to happen during heavy load periods, when failures cascade because of stress on the system. If the hydro units are running at or near full load when the plant is separated from the system, they will experience load rejections. (c) Units subjected to a load rejection are designed to go to speed-no-load until their operating mode is changed by control action. Sometimes, however, they shut down completely, and if station service is being supplied by a unit that shuts down, that source will be lost. Units can’t be started, or kept on line, without governor oil pressure, and governor oil pressure can’t be maintained without a source of station service power for the governor oil pumps. (d) Assumptions made concerning plant conditions when the transmission grid collapses, thus initiating the need for a "black start," will define the equipment requirements and operating parameters which the station service design must meet. At least one emergency power source from an automatic start-engine-driven generator should be provided for operating governor oil pumps and re-establishing generation after losing normal station service power.

2.1.3 FOR LARGE POWER PLANTS.

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

2.1.3.2 TO MEET FEDERAL ENERGY REGULATORY COMMISSION (FERC) requirements, all reservoir projects should be equipped with an engine-driven generator for emergency standby service with sufficient capacity to operate the spillway gate motors and essential auxiliaries in the dam. The unit is usually installed in or near the dam rather than in the powerhouse. It may also be used to provide emergency service to the powerhouse, although the use of long supply cables from the dam to the powerhouse could be a disadvantage.

2.1.3.3 FOR A LARGE POWER PLANT, a second automatic start emergency power source may be required in the powerhouse. Besides diesel engine-generators, small combustion turbines are an option, although they are more complex and expensive than diesel engine-generator sets.

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

2.1.4 FOR SMALL, ONE-UNIT POWER PLANTS. One station service transformer supplied from the transmission system should be provided for a normal station service bus, and an emergency station service bus should be supplied from an engine-driven generator. The emergency source should have sufficient capacity to operate the spillway gate motors and minimum essential auxiliaries in the dam and powerhouse such as unwatering pumps, governor oil pumps, and any essential preferred AC loads. e. Station service distribution system.

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

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

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

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

2.1.5 STATION SERVICE SWITCHGEAR.

2.1.5.1 METAL-CLAD SWITCHGEAR with SF6 or vacuum circuit breakers should be supplied for station service system voltage above 4.16 kV. Metal-enclosed switchgear with 600-V drawout air circuit breakers should be used on 480-V station service systems. The switchgear should be located near the station service transformers.

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

2.1.5.3 EACH SUPPLY AND BUS TIE BREAKER should be electrically operated for remote operation from the control room in attended stations. As a minimum, bus voltage indication for each bus section should be provided at the remote point where remote plant operation is provided. Transfer between the two normal sources should be automatic. Transfer to the emergency power sources should also be automatic when both normal power sources fail. Feeder switching is performed manually except for specific applications.

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

2.1.5.5 FOR 480-V STATION SERVICE SYSTEMS, a delta connected, ungrounded system is recommended for the following reasons: (a) Nature of the loads. The load in a hydroelectric power plant is made up predominantly of motor loads. In a commercial or light industrial facility, where the load is predominantly lighting, the installation of a 480/277 V, wye-connected system is more economical due to the use of higher voltages and smaller conductor sizes. These economies are not realized when the load is predominantly motor loads. For high bay lighting systems, certain installation economies may be realized through the use of 480/277-V wye-connected subsystems. (b) Physical circuit layout. Wye-connected systems allow the ability to quickly identify and locate a faulted circuit in a widely dispersed area. Although hydroelectric power plants are widely dispersed, the 480-V system is concentrated in specific geographic locales within the plant, allowing rapid location of a faulted circuit, aided by the ground detection system.

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

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

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

2.5 ESTIMATED STATION SERVICE LOAD

2.5.1 GENERAL.

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

2.5.1.2 DEMAND FACTORS USED FOR DEVELOPING station service equipment capacities can vary widely due to the type of plant (high head stand-alone power plant versus low head power plant integrated with a dam structure and navigation lock). Development of demand factors for unit auxiliaries should account for the type of auxiliaries in the plant based on trends observed at similar plants. For instance, the governor oil pump demand for a Kaplan turbine will be greater than that for the governor oil pump demand for a Francis turbine of the same output rating because of the additional hydraulic capacity needed to operate the Kaplan turbine blades. If the plant is base loaded, governor oil pumps will not cycle as often as governor oil pumps in a similar plant used for automatic generation control or peaking service.

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

2.5.1.4 CAPACITY DEFICITS IN EXISTING STATION service systems have not been caused by the designer's inability to predict unit auxiliary requirements, but by unforeseeable demands to provide service for off-site facilities added to multipurpose projects. Examples of this have been the development of extensive maintenance and warehouse facilities outside the power plant, or electrical requirements resulting from environmental protection issues such as fish bypass equipment. The station service design should have provisions for unanticipated load growth for multipurpose projects with navigation locks and fish ladders. For such projects, a minimum growth factor contingency adder of 50 percent could be justified. b. Auxiliary demand. Demand varies greatly with different auxiliaries, and the selection of demand factors requires recognition of the way various power plant equipment will be operated. One method illustrated in Table 7-1 assumes 1 hp as the equivalent of 1 kVA and on lights and heaters uses the kW rating as the kVA equivalent. The accuracy of the method is within the accuracy of the assumptions of demand and diversity. The values of demand and diversity factors correlate with trends observed in recent years on station service loads.

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

Table 7-1 (continued)

Estimated Station Service Load and Recommended Transformer Capacity

3. CONTROL SYSTEM

3.1 GENERAL

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

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

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

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

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

3.1.6 CONTROL ROOM LOCATION. In plants with a few units, the control room location with its centralized controls should provide ready access to the governor control cabinets. In plants with ultimately four or more units, the control room should be located near the center of the ultimate plant or at a location allowing ready access to the units and adjacent switchyard. The relative number and lengths of control circuits to the units and to the switchyard is a factor to consider, but is secondary to consideration of operating convenience. The control room should be an elevation above maximum high water, if there is any danger that the plant may be flooded. A decision on the location of the control room should be reached at an early stage of plant design, since many other features of the plant are affected by the control room location. Control location definitions and control modes are further described in IEEE 1010. g. Smaller plants. In smaller power plants, where indoor generator-voltage busing and switching are used, hinged instrument panels on the switchgear cubicles should be used as mounting space for main control equipment. This results in the main group of control equipment being located at the main switchgear location.

3.2 CONTROL EQUIPMENT

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

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

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

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

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

3.4 LARGE POWER PLANT CONTROL

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

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

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

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

Table 8-1
Typical Plant Control and lnstrumenl Switoh Data

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

3.5 SMALL POWER PLANT CONTROL

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

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

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

3.5.4 SCADA EQUIPMENT. Small power plants are frequently unattended and remotely controlled from an offsite location using SCADA equipment. The SCADA and communication equipment should be located in the general control area.

3.6 PROTECTIVE RELAYS

3.6.1 GENERAL. The following discussion on protective relays includes those devices which detect electrical faults or abnormal operating conditions and trip circuit breakers to isolate equipment in trouble or notify the operator through alarm devices that corrective action is required. The application of relays must be coordinated with the partitioning of the electrical system by circuit breakers, so the least amount of equipment is removed from operation following a fault, preserving the integrity of the balance of the plant's electrical system. (1) Generally, the power transmitting agency protection engineer will coordinate with the Corps of Engineers protection engineer to recommend the functional requirements of the overlapping zones of protection for the main transformers and high voltage bus and lines. The Corps of Engineers protection engineer will determine the protection required for the station service generators and transformers, main unit generators, main transformers, and powerhouse bus. (2) Electromechanical protective relays, individual solid state protective relays, multi-function protective relays, or some combination of these may be approved as appropriate for the requirements. Traditional electromechanical protective relays offer long life but may malfunction when required to operate, while many less popular designs are no longer manufactured. Individual solid state protective relays and/or multi-function protective relays offer a single solution for many applications plus continuous self-diagnostics to alarm when unable to function as required. Multi-function protective relays may be cost-competitive for generator and line protection when many individual relays would be required. When multifunction relays are selected, limited additional backup relays should be considered based upon safety, the cost of equipment lost or damaged, repairs, and the energy lost during the outage or repairs if appropriate. (3) When the protection engineer determines that redundancy is required, a backup protective relay with a different design and algorithm should be provided for reliability and security. Fully redundant protection is rarely justified even with multi-function relay applications. Generators, main transformers, and the high voltage bus are normally protected with independent differential relays. (4) When the protective relays have been approved, the protection engineer will provide or approve the settings required for the application.

3.6.2 MAIN GENERATORS. (1) The general principles of relaying practices for the generator and its excitation system are discussed in IEEE standards C37.101, C37.102, and C37.106. Unless otherwise stated, recommendations contained in the above guides apply to either attended or unattended stations. (2) Differential relays of the high speed, percentage differential type are usually provided to protect the stator windings of generators rated above 1500 kVA. (3) A high-impedance ground using a resistance loaded distribution transformer scheme is generally used, thereby limiting generator primary ground fault current to less than 25 A. A generator ground, AC overvoltage relay with a third harmonic filter is connected across the grounding impedance to sense zero-sequence voltage. If the generator is sharing a GSU transformer with another unit, a timed sequential ground relay operation to isolate and locate generator and delta bus grounds should be provided. (4) Out-of-step relays are usually provided to protect generators connected to a 500-kV power system, because the complexity of a modern EHV power system sometimes leads to severe system frequency swings, which cause generators to go out of step. The generator out-of-step relays should incorporate an offset mho and angle impedance relay system which can detect an out-of-step condition when the swing locus passes through the generator or its transformer. (5) Frequency relays, and under- and over-frequency protection, are not required for hydraulic-turbine-driven generators. (6) Temperature relays are provided for thrust and guide bearings as backup for resistance temperature detectors and indicating thermometers with alarms. The relays are set to operate at about 105o C and are connected to shut down the unit. Shutdown at 105o C will not save the babbitt on the bearing but will prevent further damage to the machine.

3.6.2 GENERATOR BREAKERS.

3.6.2.1 MOST BREAKER FAILURE RELAYING schemes operate on high phase or ground currents. When a trip signal is applied to the breaker, the breaker should open and current flow should cease within the breaker interrupting time.

The breaker failure relay is usually applied to operate lockout relays to trip backup breakers after a time delay based on the assumption the breaker has failed if current flow continues after the breaker trip circuit has been energized. These schemes do not provide adequate protection if breaker failure occurs while current is near zero immediately following synchronizing.

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

3.6.2.3 SOME BREAKER CONTROL SYSTEMS monitor the breaker trip coil using a high resistance coil relay connected in series with the trip coil. A time delay relay is required to allow the breaker to open during normal tripping without initiating an alarm.

3.6.3 PROVISION SHOULD BE MADE to trip generator breakers when there is a loss of the breaker trip circuit DC control power or complete loss of DC for the entire plant. A stored energy capacitor trip device can be used to trip the breaker in case of a loss of control power.

3.6.4 TRANSFORMER PROTECTION. (1) Transformers or transformer banks over 1500 kVA should be protected with high-speed percentage- type differential relays. The basic principles involved in transformer protection are discussed in IEEE C37.91. (2) Separate differential relay protection for generators and transformers should be provided even on unit installations without a generator circuit breaker. The relays applicable for generators can be set for much closer current balance than transformer differential relays. (3) Auto transformers can be treated as three winding transformers and protected with suitable high speed differential relays. The tertiary winding of an auto-transformer usually has a much lower kVA rating than the other windings. The current transformer ratios should be based on voltage ratios of the respective windings and all windings considered to have the same (highest) kVA rating. (4) Thermal relays supplement resistance temperature detectors and thermometers with alarm contacts. The relays are set to operate when the transformer temperature reaches a point too high for safe operation, and are connected to trip breakers unloading the transformers. These relays are important for forced-oil water-cooled transformers which may not have any capacity rating without cooling water.

3.6.5 BUS PROTECTION. (1) High-voltage switchyard buses can be protected with bus protection, but the necessity and type of bus protection depends on factors including bus configuration, relay input sources, and importance of the switchyard in the transmission system. Application of bus protection should be coordinated with the PMA or utility operating agency. The basic principles of bus protection operation are discussed in IEEE C37.97. (2) Large power plants with a complex station service system configuration should be provided with station service switchgear bus differential relay protection. (3) A ground relay should be provided on the delta connected buses of the station service switchgear. A voltage relay, connected to the broken-delta potential transformer secondary windings, is usually provided to detect grounds. A loading resistor may be placed across the broken delta to prevent possible ferro-resonance. The ground detector usually provides only an alarm indication. f. Feeder protection. Feeder circuits that operate at main generator voltage and 4160-V station service feeders should be protected with overcurrent relays having instantaneous trip units and a ground relay. The setting of the ground relay should be coordinated with the setting of the generator ground relay to prevent shutdown of a generator due to a grounded feeder.

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

3.6.7 SHUTDOWN RELAYS. The shutdown lockout relays stop the unit by operating shutdown equipment and tripping circuit breakers. The lockout relay operations are usually divided into two groups. A generator electrical lockout relay, 86GX, is initiated by protective relaying or the operator’s emergency trip switch. The generator mechanical lockout relay, 86GM, is triggered by mechanical troubles, such as bearing high temperatures or low oil pressure. The unit shutdown sequence is described in IEEE 1010. 8-7. Automatic Generation

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