HYDROELECTRIC POWER

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1.0 SCOPE

This data sheet covers hydroelectric power installations of all sizes, including the various kinds of water turbines, their hazards, and recommended safeguards.

Loss prevention recommendations related to the operation, protection, inspection, maintenance, and testing of large, salient pole, hydroelectric generators are provided. Salient pole generators used for pumped storage applications are also covered.

Round rotor, hydroelectric generators are not covered by this data sheet. Refer to Data Sheet 5-12, *AC Generators,* for recommendations related to round rotor generators.

1.1 Hazards

Electrical failure is the main hazard associated with hydroelectric generators. Insulation failure, electrical faults, and abnormal operating conditions can result in significant damage to the stator windings, core, and rotor.

Electric ac generators are also subject to mechanical failure such as bearing damage, loss of lubrication or cooling, rotor rim distortion, stator frame cracking, bearing bracket failure, and rotor pole deformation.

Electrical and mechanical failures can cause serious damage to the generator and result in cascading effects, such as lubrication oil fires and electrical system instability, that could affect other generators.

1.2 Changes

January 2023. Interim revision. Minor editorial changes were made.

2.0 LOSS PREVENTION RECOMMENDATIONS

2.1 Protection

2.1.1 General

2.1.1.1 Where combustible construction is present, install automatic sprinklers designed to provide 0.2 gpm/ft^2 (8 mm/min) over 2500 ft^2 (230 m^2) if a wet system is used and 0.2 gpm/ft^2 (8 mm/min) over 3500 ft^2 (330 m^2) if a dry system is used.

2.1.1.2 Install and protect oil storage tanks in accordance with Data Sheet 7-88, *Storage Tanks for Ignitable Liquids.*

2.1.1.3 Where possible, use FM Approved industrial fluids. Additional information on FM Approved industrial fluids is provided in Data Sheet 7-98, *Hydraulic Fluids.*

2.1.1.4 Protect cable rooms and cable trays in accordance with Data Sheet 5-31, *Cables and Bus Bars.*

2.1.1.5 Where emergency power is provided, refer to the recommendations in Data Sheet 5-23, *Design and Protection for Emergency and Standby Power Systems.*

2.1.1.6 Install and protect unit power transformers and station service transformers in accordance with Data Sheet 5-4, *Transformers.*

2.1.1.7 Install and protect unit power transformers and station service transformers in accordance with Data Sheet 5-4, *Transformers.*

2.1.1.8 Install and protect indoor switchgear enclosures in accordance with Data Sheet 5-19, *Switchgear and Circuit Breakers.*

2.1.2 Generators

2.1.2.1 Detection

2.1.2.1.1 Provide electrical protection relays to trip the generator in the event of a fault, and lock-out to prevent re-energization of the unit until a full investigation has been performed and the fault has been cleared.

2.1.2.1.2 Provide FM Approved photoelectric smoke detection or very early warning fire detection (VEWFD). At a minimum, provide detection in the generator housing above and below the stator windings or in the exhaust louver areas. Install the detection in accordance with Data Sheet 5-48, *Automatic Fire Detection,* and Data Sheet 5-40, *Fire Alarm Systems.*

2.1.2.1.3 Arrange the detection system to trip the generator upon activation. When VEWFD is used, monitor detection systems to obtain background readings before pre-alarm and alarm settings are established.

2.1.2.1.4 Design the fire protection system, if installed, to actuate upon operation of the detection system.

2.1.2.1.5 Provide electronic supervision for fire detection system trouble conditions and annunciate trouble alarms in the control room or at a constantly attended location if the station is unmanned.

2.1.2.2 Protection

Where thermoplastic insulation materials (e.g., asphalt, cloth ribbon, polyester) are installed, provide one of the following fixed special extinguishing systems for protection of the generator:

A. Automatic water spray system (open or enclosed generators)

B. Carbon dioxide (CO_2) system (enclosed generators)

C. Total flooding water mist system FM Approved for machinery in enclosures (enclosed generators), or hybrid (water and inert gas) system FM Approved for machinery in enclosures (enclosed generators)

2.1.2.2.1 When an automatic water spray system is provided to protect the generator, use the following design criteria:

A. Install spray rings above and below the stator end turns, as shown in Figure 2.

B. Provide a minimum density of 0.3 gpm/ft^2 (12 mm/min) for the upper and lower surfaces.

C. Design the system to discharge for the rundown time of the generator or 20 minutes, whichever is longer.

D. Provide interlocks to prevent discharge of the system until the generator is deenergized, forced air flow is shut down (if applicable), and any installed dampers are closed.

E. Dry out the generator following system discharge using normal air flow with the generator rotating but not energized. Continue for approximately 24 hours, or until measurements indicate the generator is dry, before electrical repair is attempted.

2.1.2.2.2 When a carbon dioxide (CO_2) system is provided to protect the generator, use the following design criteria:

A. Install the system in accordance with its listing in the Approval Guide, the manufacturer's recommendations, and Data Sheets 4-0, *Special Protection Systems,* and 4-11, *Carbon Dioxide Extinguishing Systems.*

B. Provide sufficient agent to achieve an initial CO_2 design concentration of at least 34% by volume within one minute, and maintain a minimum of 30% for the rundown time of the generator or 20 minutes, whichever is longer.

C. Provide interlocks to prevent discharge of the system until dampers and vents are closed and air flow is shut down.

2.1.2.2.3 When a water mist or hybrid (water and inert gas) system is provided to protect the generator, use the following design criteria:

A. Install the system in accordance with its listing in the *Approval Guide,* the manufacturer's recommendations, and Data Sheets 4-0, *Special Protection Systems,* and 4-2, *Water Mist Systems,* as applicable.

B. Ensure all system limitations, such as protected volume size, ventilation rate, and opening size, are met.

C. Hydraulically design the water mist or hybrid system in accordance with the manufacturer's recommendations and the system's listing in the *Approval Guide.*

D. Design the water mist or hybrid agent supply to provide discharge for the rundown time of the generator or 20 minutes, whichever is longer.

E. Provide interlocks to prevent discharge of the system until the generator is de-energized and air flow is shut down.

F. Dry out the generator following system discharge using normal air flow with the generator rotating but not energized. Continue for approximately 24 hours, or until measurements indicate the generator is dry, before electrical repair is attempted.

2.1.2.2.4 Provide FM Approved wheeled portable carbon dioxide or dry chemical extinguishers at all manned and unmanned locations. Refer to Data Sheet 4-5, *Portable Extinguishers,* to determine effective sizes and locations for the extinguishers. Protect extinguishers located outside against freezing.

2.1.2.2.5 Where small hose (1-1/2 in. [38 mm]) stations are provided, space them to allow full coverage of the area being protected. Add a water demand of 50 gpm (190 L/min) to the combined sprinkler and hydrant demand for a single hose station. Add a water demand of 100 gpm (380 L/min) when more than one hose station is provided.

2.2 Equipment and Processes

2.2.1 Mechanical

2.2.1.2 Provide water turbines with the following condition monitoring and safeguard systems:

A. A governor to adjust the water flow to maintain the generating unit’s speed and the system frequency. A hydraulic turbine governor to adjust the power output of the unit in response to operator or other supervisory commands.

B. A fail-safe governor drive mechanism to stop water flow to the turbine in the event of governor drive failure, and to protect the unit from uncontrolled runaway following sudden isolation from the electrical load.

C. A monitoring system fully integrated with plant governor and control system to facilitate automatic shutdown and alarming.

D. A monitoring system that provides measurements of the following:

1. Guide bearing vibration
2. Bearing temperatures
3. Water flow and temperature
4. Turbine vibration
5. Head cover/draft tube vibration
6. Rotational speed

E. A non-recycling overspeed trip device that will prevent the turbine from excessive overspeed. Ensure the turbine cannot attain a speed in excess of 140% of normal design speed, or a lower limit if designated by the manufacturer.

F. A second means, either manual or remote actuated, to stop the flow of water to the penstock and turbine in the event of failure of the penstock, turbine, or guide vane apparatus.

G. An alarm that will sound at a constantly attended location in the event of the development of an abnormal condition, such as any of the following:

1. Guide bearing vibration
2. Broken guide vane shear pin
3. Bearing temperatures
4. High shaft deflection
5. Water flow and temperature
6. Turbine vibration
7. Head cover/draft tube vibration
8. Rotational speed
9. Abnormal pressure due to the governing, lubricating, or cooling systems

2.2.1.2 Equip tube-type turbines, if not designed to withstand the turbine runaway speed, with an air clutch between the turbine and the generator that will disengage the generator at 125% of the design speed.

2.2.1.3 Equip tube-type turbines that do not have wicket gates with an automatically operated shutoff valve that will provide shutoff and startup functions. Have the condition of the valves and controls inspected and tested for proper operation biannually where feasible, but at least annually.

2.2.1.4 Ensure the operating procedure and training program emphasizes that brakes should not be applied during the following conditions:

A. Runaway speeds

B. Inability to close wicket gates

C. Failure of the braking logic sequence to attain zero speed within 60 seconds

2.2.1.5 Provide protective sensing devices for the following abnormal conditions. Functionally test and calibrate the protective devices annually. Install protective devices to automatically shut down the turbine on any of these abnormal conditions.

A. Automatic closing of the head gates on a flow rate of 130% of normal for a period of time greater than the closing of the governor from full open to full closed

B. Abnormal temperature

C. Abnormal flow rates of lubrication, cooling, or sealing fluids

D. Abnormal pressure due to the governing, lubricating, cooling, sealing fluids or gases

E. Broken guide vane shear pin

F. High shaft deflection

2.2.2 Electrical

2.2.2.1 Provide protective and alarm devices for salient pole hydroelectric generators in accordance with Table 1 and Figure 1.

2.2.2.2 Set protective and alarm devices based on engineering short circuit and relay coordination studies that have been performed by engineers experienced with protective relaying. Do not use the factory default settings.

2.2.2.3 Alarm and shut down the generator in a controlled manner upon detection of a field ground fault. Do not continue to operate the generator with one field ground fault.

Table 1. Recommended Protective and Alarm Devices for Salient Pole Generators

Device No.	*Protective Relay*	*Purpose*
21 or 51V	Distance protection relay or voltage controlled/restrained time over current relay	Provides backup protection for system or generator zone phase faults.
24	Volts per Hertz relay	Protects the generator from overexcitation.
25	Synchronism check relay	Prevents generator circuit breaker from closing if the generator is not in synchronism with the electrical grid or other generators.
32	Reverse power relay[1]	Anti-motoring protection for the generator and the prime mover.
40	Loss of field relay[2]	Protects the generator in the event of a loss of field.[2]
46	Negative sequence current relay	Protects the generator from unbalanced system faults.
49	RTD in stator winding	Detects overload.
49	RTD in cooling system	Detects a failure of the cooling system.
49	RTD in stator core	Detects increased temperatures from core faults.
51GN	Time overcurrent relay	Primary stator ground fault protection for low resistance grounded generators and backup stator ground fault. protection for high resistance grounded generators.
51TN[3]	Time overcurrent relay	Provides backup protection for stator ground faults (provided on step-up transformer neutral).
59	Time delay overvoltage relay	Protects the generator stator windings from overvoltage.
53	Exciter relay[4]	Protects the generator from overexcitation when the generator is offline (i.e., prior to synchronizing or during shutdown).
59GN	Time delay overvoltage relay	Primary stator ground fault protection for high resistance grounded generator.
60	Voltage balance relay	Detects blown instrument transformer fuses which renders protection relays ineffective.
61	Time over current relay	Protects against turn-to-turn faults in stator winding.
63	Transformer pressure relay[3]	Protects the generator in the event of a step up transformer fault.
64F	Field ground fault relay[5]	Generator field winding ground fault protection.

1. Reverse power protection is not required if the hydro turbine is designed for operation in pumped storage or synchronous condenser modes.
2. Undervoltage relay or overfrequency relay supervision is needed for hydrogenerators operating as synchronous condensers, or where loss of field protection is implemented using distance protection relays.
3. Applicable to unit connected transformer (i.e., via a step-up transformer).
4. This is a relay that measures the current across a field shunt to ensure the generator is not overexcited when the machine is offline and the normal V/Hz relay is not in operation.
5. Applicable to generators with slip rings.

2.2.2.4 Equip hydroelectric units used for pump-storage or power factor improvement with the following additional safety devices:

A. Out-of-step protection (Device 78) for machines while pumping in case motor pulls out of synchronism.

B. Generator field winding temperature monitors (Device 49) for locked rotor protection during motor start when machine is started as an induction motor.

C. High tail-race water level detectors (where the draft tube water level is depressed) while operating as a synchronous condenser.

2.2.2.5 Provide surge protection (arresters and, if necessary, surge capacitors) in accordance with Data Sheet 5-11, *Lightning and Surge Protection for Electrical Systems.*

2.2.2.6 Provide generator grounding and protection so ground fault currents are limited to minimize the potential for stator core damage. The two most commonly used grounding schemes are high-resistance grounding and low-resistance grounding. Solidly grounded and ungrounded generators should be converted to either scheme.

2.2.2.7 Provide ground fault protection capable of providing 100% coverage of the stator windings.

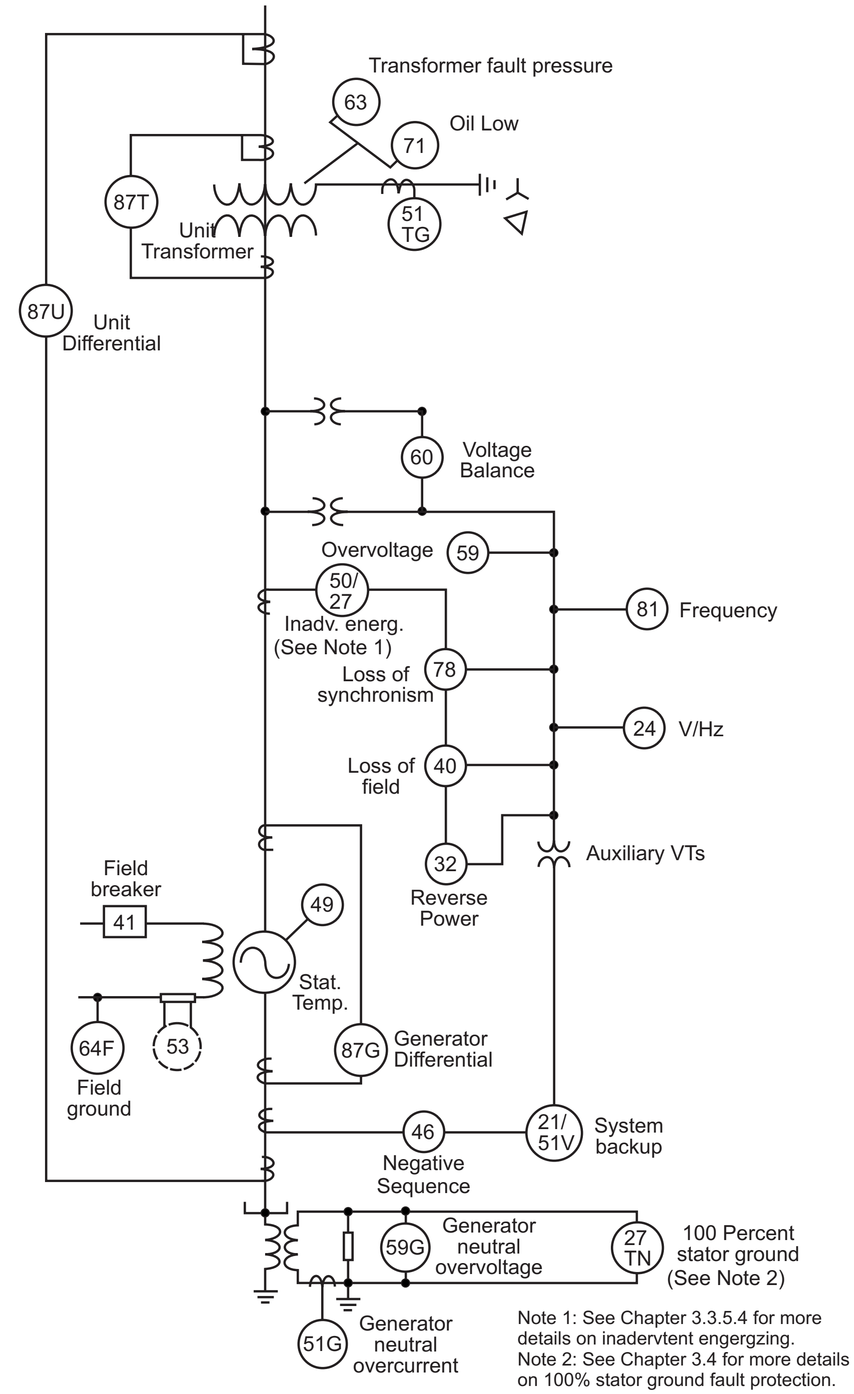

Fig. 1. Relay Schematic

2.3 Operation and Maintenance

2.3.1 Mechanical

Establish and implement a hydroelectric power equipment inspection, testing and maintenance program. See Data Sheet 9-0, *Asset Integrity*, for guidance on developing an asset integrity program.

Train operators on hydroelectric power equipment operation. See Data Sheet 10-8, *Operators*, for operator guidance.

2.3.1.1 Include the following during the annual operating inspection of the turbine and associated systems, preferably during a period of high water level:

A. Ensure the inspection involves the entire system to verify the condition of the various components, beginning at the dam and including the head gates operation and emergency system, trash racks and screens, spillway gates, penstock, surge tank (if any), generator, turbine, governor system lubrication, bearing temperatures, and wheel pits where accessible.

B. Verify the availability of routine and emergency startup and shutdown procedures. In case of power failure, power extension from another station is satisfactory.

C. For high water head as defined by the turbine manufacture, test the overspeed system annually, at initial startup, at the completion of construction of a new unit, any turbine overhaul, dewater inspection, and replacement of any components of the overspeed protection system.

D. For low water head as defined by the turbine manufacturer, follow the OEM’s instructions as overspeed system requirements vary according to the turbine design and application.

E. Test both routine and emergency methods of actuation of the spillway gates; partial openings annually, and full openings every 5 years.

2.3.1.2 Make a thorough inspection of the turbine with the system shut down and drained every 3 years.

2.3.1.3 During a dewatered inspection, perform nondestructive examination (NDE) on turbine components (turbine rotor, wicket gates, and turbine blades) in accordance with the OEM’s instructions. Removing or pulling the generator rotor may not be required. Examine stay vanes and gate surfaces using one of the following nondestructive methods: magnetic particle (MT), liquid penetrant (PT), or ultrasonic (UT). If there are any signs of cracking, or their condition is questionable, conduct a volumetric ultrasonic test. The″shadow method″ has been shown to be an effective UT procedure for this type of inspection. Wicket gate pins and wicket gate shaft should be inspected at the turbine dismantle.

2.3.1.4 Mechanical maintenance for turbine head bolts:

A. Ensure the turbine head cover, head cover bolts, flange, and rim guidance bolts are in place and properly secured.

B. Perform visual examination (VT) in accordance with a written procedure that describes the relevant visual indications.

C. If there are any signs of cracking, or the condition of the bolts is questionable, remove the bolts for further evaluation and replace them as necessary.

D. Verify the condition of the head bolts using nondestructive examination. Ultrasonic examination (UT) is the preferred method because it can detect cracks and small flaws deep within the bolts’ shanks and threaded ends with the bolts still in the assembly.

1. Ensure only personnel certified in nondestructive testing perform examinations and evaluate the results.

2. Ensure a qualified, written NDE procedure is used.

3. If there are any signs of cracking, or the condition of the bolts is questionable, remove the bolts for further evaluation and replace as necessary.

2.3.1.5 Ensure a thorough inspection of the penstocks and surge tanks is made every 5 years by personnel qualified and equipped to do this work.

2.3.1.6 Check trash racks, screens, and intake structures periodically to be sure they are in good repair and unobstructed. The frequency of these checks will depend on water conditions. During flood periods, when there is likely to be more debris in the water, a check every 8-hour shift may be necessary. Make a thorough check annually when the canal or forebay is dewatered.

2.3.1.7 Check generators that are subject to oil accumulations on the underside of the stator windings periodically. Base the frequency on operating conditions. Clean the windings when necessary.

2.3.1.8 Keep wheel pits free of accumulated oil and grease.

2.3.1.9 Maintain prints/drawings for hydro turbine spares.

2.3.2 Electrical

2.3.2.1 In-Service

2.3.2.1.1 Operate the generator in accordance with the manufacturer's operating instructions and within the prescribed mechanical, thermal, and electrical limits (i.e., the capability curve).

2.3.2.1.2 Consult the manufacturer before operating the generator with part of the stator winding path or individual stator coils bypassed. If operating a generator in this condition, check the protection settings to ensure electrical protection for the generator is not compromised. Do not operate the generator in this condition for an extended period. This is only a temporary measure until permanent repairs can be carried out.

2.3.2.1.3 Periodically check generators that are subject to oil accumulations on the underside of the stator windings. Base the frequency on operating conditions. Clean the windings when necessary.

2.3.2.1.4 Provide built-in electric heaters for important motors, generators, and switchgear in damp locations or for use during shutdown periods.

2.3.2.2 Generator Dismantle Intervals

Hydroelectric generators undergo two types of dismantles: major dismantles and minor dismantles. A major dismantle usually involves the removal of the rotor from the generator.

2.3.2.2.1 Perform a generator major dismantle 1 to 3 years after commissioning, preferably before the expiration of the generator warranty.

2.3.2.2.2 Schedule further major dismantles based on the following factors:

- Visual inspections
- Operating history
- Machine availability
- Electrical testing results
- Condition monitoring results
- Failure history
- Equipment alerts
- Maintenance history
- Previous dismantle report
- Exposure to severe or abnormal operating conditions

2.3.2.2.2.1 For application of condition-based maintenance, consider providing the following commercially available monitoring systems on the generator:

- Stator winding temperature sensors
- Rotor pole temperature sensors
- Air gap monitor
- Partial discharge detectors
- Bearing vibration sensors
- Stator frame vibration sensors

The level of condition monitoring provided on a generator will depend on factors such as size, type, application, criticality, and any pre-existing problems with the generator. Refer to Section 3.0, Support for Recommendations, for guidance on condition-monitoring systems.

2.3.2.2.3 In the absence of any method for determining the intervals between major dismantles, follow the original equipment manufacturer's instructions.

2.3.2.3 Visual Inspection

Have a generator specialist perform a visual inspection at each dismantle and at all other opportunities. See Table 4 for a list of visual indications and the likely cause of each.

2.3.2.4 Testing

2.3.2.4.1 Table 2 lists the electrical and mechanical tests that are typically performed at major and minor generator dismantles. Have tests performed based on condition monitoring data, visual inspections, operating experience, and failure history.

Table 2. Generator Tests

Component	*Test*	*Major*	*Minor*
Stator windings	Insulation Resistance	X	X
	Polarization Index	X	X
	DC Conductivity	X	X
	Capacitance	X	X
	Capacitance Tip Up	X	X
	Power Factor	X	X
	Power Factor Tip Up	X	X
	Off-line Partial Discharge	X	X
	Surge Comparison	X	
	Blackout	X	
	Semi conductive Coating Contact Resistance	X	
	Wedge Tightness	X	
	Side Clearance	X	
	Stator End-Winding Resonance	X	
Stator Core	Loop Test	X	
	Visual inspection for hot spots	X	X
Rotor windings	Insulation Resistance	X	X
	Pole Voltage Drop	X	X
	DC Conductivity Test	X	X
	NDE of spider for cracks	X	
Static Exciter	Visual inspection for cleanliness and condition	X	X
	Check rectifier integrity	X	
Rotating Exciter	Visual inspection for cleanliness and condition	X	X
	Perform similar electrical tests as for generator	X	
Brushless Exciter	Visual inspection for cleanliness and condition	X	X
	Check diode integrity	X	

2.3.2.4.2 Treat the pilot-mounted generator of a rotating exciter as a small generator and subject it to the same electrical tests as those performed on the main generator.

2.3.2.4.3 Have generator circuit breakers, protection relays, batteries, cables, and surge arrestors tested in accordance with DS 5-19, *Electrical Testing,* at both the major and the minor dismantles.

2.3.2.4.4 Have generator auxiliaries, such as the lubrication oil system, water cooling system, and air cooling/filtering system, inspected during dismantles, where applicable.

2.3.2.5 Overvoltage (Hipot) Testing

2.3.2.5.1 Overvoltage testing is a potentially destructive test that provides little diagnostic information. It is a pass/fail test that is normally conducted when an in-service failure is intolerable due to the critical nature of the generator. An overvoltage test is not necessary if appropriate condition-monitoring systems are in place, good results have been obtained from partial discharge monitoring and insulation resistance testing, and there is no reason to suspect a problem with the insulation.

2.3.2.5.2 Have an overvoltage test carried out under the following conditions:

A. As part of commissioning.

B. After a repair (a repair is considered to be any work requiring the removal of stator bars to restack the core, rewind the generator, or any other work involving the stator bar insulation; re-wedging, end winding re- bracing, and core tightening may also warrant an overvoltage test).

C. After any incident that raises doubts about the integrity of the insulation, such as serious water leaks, overheating, fire exposure or oil ingress.

2.3.2.5.3 For modern thermoset (epoxy-mica) stator insulation, an AC overvoltage test conducted at power frequency or 0.1 Hz is preferred to a DC overvoltage test. These insulation systems have almost infinite resistivity and a DC voltage would only stress a very thin layer of the insulation. An AC overvoltage test will produce a more even electric stress distribution across the entire thickness of the insulation. AC overvoltage tests are therefore more searching.

2.3.2.5.4 DC overvoltage tests are acceptable for older thermoplastic (asphalt-mica) stator insulation. These insulation systems absorb moisture and therefore have a finite resistivity. AC or DC voltage applied across these insulation systems produce similar electric stress distributions.

2.3.2.5.5 The preferred way of conducting a DC overvoltage test is the ramp test method. In this method, voltage is raised at a rate of 1 kV/min while leakage current is measured continuously. This is a sensitive method of detecting a sudden rise in leakage current because capacitive charging current will be constant during the test, increasing the chances of detecting defective insulation and aborting the test before the insulation is punctured.

2.3.2.5.6 An alternative is to increase the applied voltage in 1 kV steps and to measure the leakage current after 1 minute. This test is less sensitive because capacitive charging current may mask a sudden rise in leakage current.

2.3.2.5.7 Adhere to the recommended maximum voltages for overvoltage testing provided in Table 3.

Table 3. Recommended Maximum Voltages for Overvoltage Testing

Test	*Voltage*	*Winding Condition*
AC	(2E + 1)kV	New
	1.25 to 1.5 x E kV	In service
DC	1.7(2E + 1)kV	New
	1.25 to 1.5 x (1.7E) kV	In service

Note: E is the rated phase-to-phasse voltage of the generator.

2.3.2.5.8 Do not DC overvoltage test a generator close to the end of its design life.

2.3.2.5.9 Do not perform surge comparison testing of the stator.

2.4 Contingency Planning

2.4.1 Equipment Contingency Planning

When a hydroelectric power equipment breakdown would result in an unplanned outage to site processes and systems considered key to the continuity of operations, develop and maintain a documented, viable hydroelectric power equipment contingency plan per Data Sheet 9-0, *Asset Integrity*. See Appendix C of that data sheet for guidance on the process of developing and maintaining a viable equipment contingency plan. Also refer to sparing, rental, and redundant equipment mitigation strategy guidance in that data sheet.

In addition, include the following elements in the contingency planning process specific to hydroelectric power equipment:

- Site and equipment accessibility
- Plant configuration/design impacts on access to equipment for repair/replacement
- Generator repair capabilities on site, including availability of salient pole generator components

2.4.2 Sparing

Sparing can be a mitigation strategy to reduce the downtime caused by a hydroelectric power equipment breakdown depending on the type, compatibility, availability, fitness for the intended service, and viability of the sparing. For general sparing guidance, see Data Sheet 9-0, *Asset Integrity*.

2.4.2.1 Routine Spares

Routine hydroelectric power equipment spares are spares that are considered to be consumables. These spares are expected to be put into service under normal operating conditions over the course of the life of the hydroelectric power equipment, but not reduce equipment downtime in the event of a breakdown. This can include sparing recommended by the original equipment manufacturer. See Section 3.7 for routine spare guidance.

3.0 SUPPORT FOR RECOMMENDATIONS

3.1 Visual Indications

Table 4 lists visual indications and their likely causes. Visual inspection includes the use of borescopes, fiberscopes, robotic cameras, and similar equipment.

Table 4. Visual Indications and Their Likely Causes

Component	*Visual Indication*	*Likely Cause*
Stator Frame	Loose generator frame footing bolts	Foundationproblems
	Cracked grouting around generator footings	Foundationproblems
	Eccentric air gap clearance (measured along the length of the stator bore)	Foundation problems or distortion of rotor rim or stator frame; may also be due to bearing problems
	Internal corrosion of generator casing	Faulty space heaters
	Paint discoloration and/or blistering on the stator frame, casing and core	Overload operation or improper cooling
Stator core and windings	Carbon dust	Poor sealing between generator and exciter
	Red iron oxide powder	Loose core
	Greasing (forming a magnetic mixture of dust and oil)	Fretting of core laminations or loose stator winding wedges
	Blocked cooling vents	Dirty or faulty air filters
	Damaged tops of stator core teeth	FOD from pieces of core plate, space blocks and foreign material in stator bore
	Bent or broken laminations	Careless rotor removal
	Back of core burning	Excessive current transfer between core laminations and stator frame keybars
	Bulging or deformation of stator bar insulation (applicable to asphalt-mica insulation systems only)	Asphalt migration due to excessive temperatures
	Soft spots on stator bar insulation	Asphalt migration due to excessive temperatures
	Tape separation (separation of stator insulation due to friction between stator slot and stator bar as the bar expands and contracts)	Excessive thermal cycling
	Girth cracking (stator insulation cracks completely around the girth of the stator bar and separates from the bar forming a neck)	Excessive thermal cycling, high temperature operation
	Dry and brittle insulation, discolored insulation, powder accumulations in the stator core slot	Thermal aging due to operation at excessive temperature
	Burn marks, whitish or brownish powder on stator bars	Corona activity
	Pinpoints of lights during blackout inspection	Slot partial discharge activity
	Strong ozone smell	Slot partial discharge activity
	Hollow sound when stator wedges are tapped	Loose stator bars
	Stator wedges migrating axially beyond core ends	Loose stator bars
	Side packing filler strips migrating up from core slots	Loose stator bars
Rotor poles and windings, including damper windings	Broken, loose or overheated	Excessive vibration, poorly made
	inter-pole connections	connections and metal fatigue
	Pole insulation migration or creepage	Age related failure or excessive thermal cycling
	Looseness or fretting in dovetail key assembly	Age related failure, excessive vibration or excessive thermal cycling
	Cracking or looseness of top or bottom pole collars	Age related failure, excessive vibration or excessive thermal cycling
	Overheating at axial ends of pole pieces	Abnormal operation of the generator (e.g., loss of field operation)
	Overheating of damper winding circuit	Abnormal operation of the generator (e.g., unbalanced loading, motoring, loss of field operation)

Table 4. Visual Indications and Their Likely Causes (continued)

Component	*Visual Indication*	*Likely Cause*
Bearings	Imbedded foreign material in babbitt	Contamination of lubrication oil
	Pitting of bearing or shaft surfaces	Poor shaft grounding or faulty bearing insulation
Component	Visual Indication	Likely Cause
Fan	Cracks at roots or welds of cooling fan	Fatigue
Brake	Distorted, pitted or scored brake ring	Poor or incorrect braking or jacking operation, or worn brake shoe
	Worn brake shoe	General wear or poor braking operation
Lubrication oil	Discoloration, dirt and metal particles in lubrication oil	Bearing damage or contamination of lubrication system
Excitation system	Accelerated wear of slip ring brushes	Possible high harmonic problem with field current or high machine vibration
	Discoloration of brush springs	Overheating of brushes or poor brush pressure

3.2 Generator Tests

Table 5 lists generator tests, the failure mode each test is capable of detecting, and the acceptance criteria for each test.

Table 5. Generator Tests, Failure Modes, and Acceptance Criteria

Test	*Test Method*	*Tested Component*	*Detected Failure Mode*	*Acceptance Criteria*
Insulation Resistance	Apply dc voltage for 1 minute and measure leakage current.	Stator and windings rotor	Contamination, defects, and deterioration of ground insulation (slot insulation for rotor windings or ground wall insulation for stator windings)	For pre-1970 vintage machines, minimum resistance should be about (E +1) MΩ. Where E is the rated phase to phase voltage in kV for stator windings or the rated dc voltage in kV for rotor windings. For post-1970 vintage machines, minimum resistance should be about 100 MΩ.
Polarization Index	Determine the ratio of the 10 minute and 1 minute insulation resistances.	Stator and windings rotor	Contamination, defects, water ingress and deterioration of ground insulation	A polarization index (PI) equal to or greater than 2 is an indication the insulation is clean and dry. However, PI values much higher than 2 indicate the insulation is dry and brittle.
DC Conductivity	Pass a dc current through the stator and rotor winding and measure the voltage across the winding to determine resistance.	Stator and rotor windings	Broken and cracked stator and rotor bars; poor connections; shorted turns in rotor winding	Compare the dc resistance of each winding; the resistances should be within 1% of each other (for form wound machines).
Capacitance Tip-Up	Measure the capacitance of each stator winding phase at about 20% line to ground voltage and then again at 100% line to ground voltage. The tip-up is the percentage difference between the two capacitances.	Stator windings	Partial discharge activity due to ground wall insulation deterioration from thermal degradation or load cycling	Epoxy mica: maximum tip-up of 1%. Asphaltic mica: maximum tip-up of 3% to 4%.
Power Factor	Apply an ac voltage and measure the power factor of each stator winding (one phase at a time with the other two phases grounded).	Stator windings	Ground wall insulation deterioration due to thermal degradation or water ingress	Epoxy mica: maximum power factor of 0.5%. Asphaltic mica: maximum power factor of 3% to 5%. A 1% increase in trended power factor is serious. Increasing power factor with decreasing capacitance indicates thermal deterioration. Increasing power factor with increasing capacitance indicates water absorption.

Table 5. Generator Tests, Failure Modes, and Acceptance Criteria (continued)

Test	*Test Method*	*Tested Component*	*Detected Failure Mode*	*Acceptance Criteria*
Power Factor Tip-Up	Measure the power factor of each stator windingphase at about 20% line to ground voltage and then again at 100% line to ground voltage. The tip-up is the difference between the two power factors.	Stator windings	Partial discharge activity due to ground wall insulation deterioration from thermal degradation or load cycling.	Trend tip-up values. An increasing trend indicates increasing partial discharge activity.
Partial Discharge	Apply line to ground ac voltage to one phase at a time and hold for 10 to 15 minutes. Then measure partial discharge activity at the machine terminals.	Stator windings	Ground wall insulation deterioration	Trend peak partial discharge magnitude. Doubling of partial discharge activity every 6 months indicates serious deterioration.
Surge Comparison	Apply a surge voltage with a rise time of 100 ns at the machine terminals for each phase. Increase the surge voltage gradually until 2.6 times line to ground voltage. Measure the waveform on an oscilloscope.	Stator windings	Turn-to-turn insulation deterioration	Changes in the waveform indicate a puncture of the turn insulation.This is a pass/fail test.
Blackout	Using a UV camera, check for pinpoints of light when the stator winding is energized at line to ground voltage (one phase at a time).	Stator windings	Tracking due to contamination of end-windings or deteriorated semiconductive coating	Pinpoints of light indicate partial discharge activity. Increasing pinpoints of light mean the problem is worsening.
Semiconductive Coating Contact Resistance	Measure the resistance of the semiconductive coating to the stator core.	Stator windings greater than 6 kV with a semiconductive coating	Deterioration of semiconductive coating and loose stator bars leading to high slot partial discharge activity	A maximum resistance of 2 kΩ. A resistance greater than 5 kΩ at phase end coils, slot discharge will occur.
Wedge Tap	Tap each end of each wedge with a hammer and either listen to thesound or measure the resulting vibration. A loose wedge will produce an undamped vibration signal and have a dull sound. A tight wedge will produce a damped vibration signal and have a “ping” sound.	Form wound stator windings; not applicable toglobal VPI coils	Loose stator bars due to poorly installed or loose wedges	No more than 25% of the wedges should be loose. No wedges at the end ofthe slot should be loose. Two or more adjacent wedges in the same slot should not be loose. No wedges should be cracked.

Table 5. Generator Tests, Failure Modes, and Acceptance Criteria (continued)

Test	*Test Method*	*Tested Component*	*Detected Failure Mode*	*Acceptance Criteria*
Side Clearance	Remove wedges from some of the slots housing the phase end coils. Slide feeler gauges between the coil and the side of the slot to determine the largest feeler gauge that will fit and slide back and forth along the slot.	Form wound stator windings; not applicable to global VPI coils	Loose stator bars	Epoxy mica: no thicker than 0.125 mm. Asphaltic mica: no thicker than 0.5 mm.
Stator End-Winding Resonance	Tap the end windings with a hammer and use accelerometers to measure the vibration in the coil. Also, listen to the sound of the winding after it has been hit. A “ping” sound indicates a tight end winding and a dull sound indicates a loose end winding.	Form wound stator end windings	Loose end windings	A resonant frequency within 3 Hz of twice power frequency indicates end winding vibration will occur. Damping of the vibration, as well as the resonant frequency, should be trended.Changes in either parameter will indicate deterioration of end winding bracing.
Open Circuit	Measure generator open circuit voltage as a function of field current.	Rotor windings	Shorted rotor windings	Compare the measured results against the known results obtained for a healthy rotor.
Loop Test	Excite the core to produce 100% back of core flux and allow the core to soak for at least 30 minutes (up to2 hours for large machines). Take temperature readings every 15 minutes to ensure the excited core does not undergo thermal runaway due to lack of cooling.	Stator core	Shorted or damaged core laminations	Hot spots with a temperature difference of between 41ºF (5ºC) to 50ºF (10ºC) indicate core defects.

3.3 Failure Modes and Abnormal Operating Conditions

This section briefly describes the common major hazards to salient pole hydrogenerators.

3.3.1 Core

The stator core is made up of steel laminations. These laminations are insulated from one another to reduce the amount of eddy currents that are induced in the core. Eddy currents generate heat and losses in the generator. Deterioration of the interlaminar insulation will result in overheating and damage to the core. This damage can be severe and could result in melting of the core. Causes of core interlaminar insulation damage are described in the following sections.

3.3.1.1 Thermal Deterioration

Overheating the core will result in deterioration of the interlaminar insulation. If varnish is used as the insulation, overheating of the core will drive off solvents in the varnish, making it dry and brittle and causing it to eventually break down.

The causes of core overheating include the following:

A. Blocked or dirty air filters in air-cooled machines will reduce the air flow through the generator and result in overheating.

B. High ambient temperatures in open ventilated, air-cooled machines will reduce the heat transfer capability of the cooling system and result in overheating.

C. Grease and dirt blocking vent holes and cooling passages in the generator will result in localized overheating of the core in areas where vent holes and cooling passages are blocked.

3.3.1.2 Electrical Deterioration

Abnormal operating conditions and electrical faults can also lead to overheating of the core. These abnormal conditions and faults include the following:

A. Underexcitation. When the generator operates in an underexcited condition (i.e., with a leading power factor), leakage magnetic flux at the ends of the stator core is very high. This will result in high temperatures at the core ends. There will also be an increase in circulating currents, which will contribute to overheating of the core ends.

B. Loss of field. An extreme example of underexcitation is when the generator loses its field. Stray flux and circulating currents are significantly higher than when the generator is operating in an underexcited condition and core end overheating will be severe.

C. Overexcitation. Failure of the excitation system or voltage regulator can cause the generator to be overexcited. This results in very high magnetic flux in the core, which over-saturates the core steel. Very high temperaturesare generated that could cause the core laminations to fuse together and, in the worst case, melt the core.

D. Stator winding faults. Electrical faults involving the winding generate high energy that could cause the core laminations to melt in the vicinity of the fault.

E. Faulty core through-bolt insulation. Through-bolts are used to hold some cores together. These through-bolts have to be insulated to prevent shorting of core laminations. Failure of this insulation will cause increased eddy currents in the shorted portion of the core.

3.3.1.3 Mechanical Deterioration

Vibration and impact damage are also leading causes of mechanical deterioration of core interlaminar insulation. This is especially true for hydrogenerators that have a more flexible core than a turbo-generator due to the larger diameter-to-height ratio of the core. Vibration and impact damage can occur due to the following:

A. Deterioration of stator frame or core supports. The cores of large salient pole hydrogenerators are constructed in several segments. Movement of the different core segments can occur due to deterioration of the stator frame supports or generator foundations. This can result in mechanical damage to the core.

B. Core vibrations. Improperly supported cores within the stator frame, magnetic forces, and unbalanced phase loading can cause high core vibrations. This will result in fretting damage to the core interlaminar insulation and lead to core overheating and melting. This effect is greater at the core teeth than the back of core because of the higher magnetic flux density in this area, as well as the lower mechanical strength of this part of the core. Teeth can chatter and break off, causing foreign object damage to the generator.

C. Stator-rotor rubs. Bearing damage, rotor ground faults, and high vibration of the generator can result in stator-rotor rubs. This will short circuit the core laminations at the point of rubbing and result in localized overheating of the core. An uneven air gap between the stator and rotor can also cause “pullover,” where the higher electromagnetic forces at the narrower air gap cause the rotor to pull over towards the stator and potentially rub the stator core.

D. Foreign object damage. Debris, bolts, nuts, tools, loose pieces of core plate, broken core spacers in the stator bore will cause damage to the top of the core laminations. The damaged laminations are often short circuited and will result in localized overheating of the core.

E. Poor handling. When the rotor is removed from the generator, careless handling will often result in core laminations being bent or broken. These damaged laminations could short together and result in localized overheating of the core.

3.3.2 Stator

Form wound stator bar insulation consists of three components:

A. Groundwall insulation, which provides the main insulation between the stator bar and the grounded core.

B. Turn insulation, which provides insulation between individual turns within each stator bar.

C. Strand insulation, which provides insulation between individual strands in each turn.

Stator winding failures occur when either the groundwall or turn insulation fails and allows a short circuit to occur.

Failure of strand insulation does not result in immediate winding failure, but will give rise to circulating currents within the stator bar and cause local temperatures to rise. This will accelerate localized thermal aging of the stator insulation and eventually lead to failure. Causes of ground-wall and turn insulation failure are described in the following sections.

3.3.2.1 Thermal Deterioration

Thermal deterioration occurs when the generator is operated at temperatures in excess of the thermal rating of the stator insulation. This is an oxidation process that involves the breakdown of chemical bonds in the organic components of the insulation. The loss of bonding strength causes mica tape layers in the insulation to separate and the conductors to become loose. The loose conductors will rub together and damage the insulation, ultimately resulting in electrical shorts. Delamination of the mica tape layers also creates voids in the insulation where partial discharge activity can take place, eventually eroding a hole in the insulation and causing an electrical short to occur.

In older generators that use thermoplastic (asphalt mica) insulation, high temperatures can cause the asphalt to flow and bleed out of the tape layers.

The causes of thermal deterioration include the following:

A. Overloading of the generator

B. Poor design or poor manufacturing

C. Poor cooling caused by high ambient temperature, blocked air filters, plugged heat exchanger tubes, and blocked generator cooling passages and vent holes

D. Overexcited and underexcited operation of the generator

E. Negative sequence currents caused by phase imbalance of the stator currents

F. High harmonics in the electrical system contributing to increased stator and core heating

3.3.2.2 Partial Discharge

Partial discharge generally refers to electrical arcing that occurs in gas (air or hydrogen) filled voids within the stator groundwall insulation.

Electrical stress across these voids is very high and causes the gas to breakdown and an arc to occur. The arc degrades the insulation at the walls of the void. Continuous partial discharge activity in the void will eventually erode a hole through the insulation and result in a ground fault.Partial discharge activity can also occur at the interface between the stator copper conductor and its insulation, as well as between the stator groundwall insulation and the stator slot. Partial discharge monitoring is most effective in machines rated 4.0 kV and above, but it has been applied with success in machines rated as low as 2.3 kV by measuring partial discharge activity as the stator terminal voltage is slowly raised.

3.3.2.3 Corona

Corona is a special type of partial discharge activity that occurs when a gas is subjected to high electric stress. Corona in generators occurs mainly in air-cooled machines rated 6 kV and above. It is typically found at the stator end windings (especially between phase coils) if there is insufficient separation between adjacent stator bars, especially between stator bars of different phases.

The causes of insufficient separation of the stator end windings include the following:

A. Poor installation of stator coils

B. Degradation of end winding blocking

C. Operation of the generator at a higher altitude than it was originally designed for (the breakdown strength of air is reduced at lower pressures)

3.3.2.4 Load Cycling

Load cycling causes insulation failure as a result of the difference in thermal expansion between the copper stator bar and the groundwall insulation. Copper expands faster than groundwall insulation and will result in an axial shear stress between the groundwall insulation and the copper bar. With repetitive load cycles the copper will eventually separate from the groundwall insulation. The gap created will allow partial discharge activity to occur. The gap also allows the copper conductors in the bar to become loose and vibrate, leading to damage of the insulation.

3.3.2.5 Loose Stator Bars

This phenomenon occurs only with stator bars that use thermoset insulation in machines not manufactured using the global vacuum pressure impregnated (VPI) method. Thermoplastic insulation is used in older machines. Thermoplastic insulation will expand into the slot to keep the stator bar tight within the slot. Thermoset insulation is rigid, so loose stator bars are more likely to be a problem in modern machines using these insulation systems.

Loose stator bars will vibrate radially in the slot. This causes the insulation to become abraded by the rough surface of the slot. Movement of the stator bar in the slot also generates slot discharge which, over time, becomes partial discharge when the semiconductive layer over the stator bar has been abraded away. Slot discharge and partial discharge will accelerate the deterioration of the insulation.

Stator bars can also become loose due to insulation shrinkage with age, loose wedges, and loose side ripple springs.

3.3.2.6 Faulty Semiconductive Coating

Stator bars in machines rated 6 kV and greater are usually coated with paint or tape that uses carbon black powder to give the coating a semiconductive property. The purpose of the coating is to reduce partial discharge activity between the stator bar and the core. However, oxidation of the carbon black can occur due to partial discharge activity or localized areas of high resistance in the coating. This will reduce the effectiveness of the semiconductive coating and will allow more partial discharge activity to occur, eventually leading to insulation failure.

3.3.2.7 Overvoltages

Overvoltages due to lightning, electrical faults, and switching will cause insulation to fail if it is stressed beyond its withstand capability.

3.3.2.8 Contamination

Unenclosed, air-cooled hydrogenerators often operate in environments where they are exposed to contaminants such as dust, salt air, moisture, and chemicals. These unenclosed generators are susceptible to electrical tracking, erosion, and chemical attack as a result of these contaminants.

3.3.3 Rotor

In general, there are two types of salient pole rotor windings.

For small generators (less than 50 MW), rectangular cross section, magnet wire is wound in several hundred layers on the pole body. The rotor winding is many layers wide as well as many layers deep from pole root to tip.

For larger generators (more than 50 MW), flat, thin copper strips are wound on the pole body with each strip stacked on top of another, with the thin edge of the strips against the pole body. The rotor winding is generally one strip wide, stacked several layers deep from pole root to tip.

Rotor insulation consists of two components: (1) pole insulation, which provides the ground insulation between the pole winding and the pole body, and (2) turn insulation, which provides insulation between the individual turns of the rotor winding for each pole.

The pole insulation for both small and large generators is usually the same. In modern machines, this consists of insulating glass laminate washers or collars at the pole tip and root as well as insulating Nomex strips placed between the winding and the pole body.

The turn insulation in smaller generators consists of the enamel on the magnet wire. Some modern generators have a Dacron glass tape over the magnet wire. In larger generators, the turn insulation consists of either an insulating Nomex separator placed between each flat copper strip, or Nomex tape wrapped around the copper strips.

The entire pole is sometimes dipped in a thermosetting resin. The poles are then bolted to the rotor rim.

3.3.3.1 Failure of Inter-Pole Connections

Each pole in a salient pole rotor is connected in series by bolted or brazed inter-pole connections. The inter-pole connections may be either solid conductor or laminated (i.e., leaved) conductor. During operation, the rotor poles will move relative to one another, causing the inter-pole connections to flex. Over time, mechanical fatigue can cause the inter-pole connections to break, resulting in an open field winding. This has been known to occur even with flexible, laminated inter-pole connections.

Flexing of the rotor poles can also cause the insulation at the inter-pole connections to fail or the contact resistance at the inter-pole connections to increase. This can result in overheating of the inter-pole connection.

3.3.3.2 Rotor Insulation Failure

Rotor winding failures can also occur when either the pole or turn insulation fails and allows a short circuit to occur.

The rotor windings are electrically isolated from the pole body and rotor rim. Therefore failure of the slot insulation allowing a single ground fault to occur will not have an immediate impact on the generator. However, the consequence of a second ground fault is high and it is not advisable to continue operating the generator for any significant period of time with a single rotor ground fault. Two rotor ground faults will result in enough circulating current to melt the pole forging and generate enough unbalance to cause mechanical damage to the generator.

Because the rotor voltage is dc, turn insulation failures do not result in very high current. It is possible for the generator to continue operating with shorted rotor turns. However, if too many shorted turns occur, this could be a sign that a rotor ground fault is likely. Shorted turns also result in increased vibration due to the unsymmetrical magnetic field.

Causes of pole and turn insulation failure are described in the following sections.

3.3.3.2.1 Thermal Deterioration

Thermal deterioration occurs when the generator is operated at temperatures in excess of the thermal rating of the rotor insulation. This causes theinsulation to discolor, crack, blister, and become brittle. Turn-to-turn faults and ground faults will occur when the insulation loses its strength.

Causes of thermal deterioration include the following:

A. Overloading the generator

B. Poor design or poor manufacturing

C. Poor cooling

D. Overexcited operation of the generator

E. Negative sequence currents due to system imbalances

3.3.3.2.2 Mechanical Deterioration

Rotor windings are under large centrifugal stress. Over time this can cause the insulation to crack, especially if the insulation has been thermally aged. Turn-to-turn and ground faults will occur.

Centrifugal forces on the rotor windings can also cause winding bracing to become loose and allow the rotor conductors to abrade. This will wear away insulation and lead to turn-to-turn faults or ground faults.

Load cycling and overspeed events will aggravate this failure mode. Thermal deterioration of insulation or bracing can also aggravate this failure mode by allowing the windings to become loose.

3.3.3.2.3 Environment

The majority of hydrogenerators are open, air-cooled units. Abrasive particles in the atmosphere such as sand and coal will erode the rotor winding insulation and lead to turn-to-turn or ground faults.

The open, air-cooled design also allows contaminants such as moisture, salt, chemicals, conductive dust, and oil mist to expose the rotor windings.Corrosive contaminants can deteriorate the rotor winding insulation and lead to turn-to-turn or ground faults. Conductive contaminants will reduce the insulation creepage distance and lead to turn-to-turn or ground faults.

3.3.4 Bearing Damage

Voltages can develop on the turbine-generator shaft during normal operation. This is a result of magnetic flux and the electrostatic effects involving the movement of particles in cooling gases and charged lubrication oils.

Substantial currents will flow through the bearings to ground if shaft voltages are not kept to a minimum. Current flow across the oil film at the bearing will result in electrical discharges. These discharges will pit thebearing surfaces, increasing the coefficient of friction and altering the flow of oil at the bearing. Eventually, bearing failure will occur.

Shaft voltage is kept to a minimum by shaft grounding devices such as copper braid or carbon brushes. Bearing insulation is also important to prevent flow of current due to shaft voltages.

3.3.5 Abnormal Electrical Conditions

3.3.5.1 Loss of Field

When a synchronous generator loses excitation, it operates as an induction generator and runs slightly above synchronous speed. Induced currents flow in the rotor iron causing overheating. The stator winding current may increase to 200% of rated current, which also results in overheating.

Loss of excitation or reduced excitation (underexcitation) can occur as a result of one or more of the following:

A. Loss of field to main exciter

B. Accidental tripping of field breaker

C. Short circuits in field circuits, or in exciter armature

D. Poor brush contact in exciter

E. Reduced frequency because of exciter control problems

F. Regulator failure

G. Loss of supply to excitation system

Loss of excitation can be detected by a relay that senses reactive power flowing from the system into the generator, or by a change in generator impedance. Such a loss-of-field relay can be used to actuate an alarm or a trip. This alarm, actuated at a moderate level of impedance loss, alerts the operator to the reduction of excitation and permits him to take steps to restore excitation. If the terminal voltage drop increases to the point of endangering the system stability, the trip functions, taking the generator out of the system.

3.3.5.2 Synchronization Errors

When a generator is tied into a utility bus, it should, when being brought on line, be carefully synchronized with the power in the system. If it is synchronized out of phase, it is electrically equivalent to imposing a three- phase fault on the generator terminal, and very high electrical torque can be developed in the stator. In some cases, the torque can be sufficient to tear out foundation bolts, damage couplings, or loosen stator windings.

One generator manufacturer recommends that the generator not be connected into the system if it is out of phase by more than 10 degrees electrical angle, or if the voltage is mismatched by more than 5%. A synchronism check relay can be installed to supervise manual synchronization. This relay checks the slip (difference in frequency) between the generator voltage and the system voltage, and produces an enabling output that permits synchronization as long as the slip is less than a preset value.

A generator also can be synchronized automatically by use of an automatic synchronization relay system.

3.3.5.3 Field Ground

Because the rotor winding, pole pieces, and rim are isolated from ground, a single field ground usually does not cause any problems with the operation of the generator. However, the generator should be taken off-line and inspected as soon as possible. The consequence of a second field ground is very high. A second field ground will result in circulating current between the two field ground locations. This current will flow through the rotor rim and pole pieces, depending on the field ground locations. This partially shorted field can generate enough magnetic unbalance to cause severe vibration and damage to the generator.

3.3.5.4 Inadvertent Energizing

Inadvertent or accidental energizing of generators that are out of service and off-line has occurred frequently enough to justify a dedicated protective function to detect this condition. Human error has been one of the main causes of this hazard, especially with electric utility unit-connected generators.

Protective functions used to detect this condition are armed when the generator is taken out of service. The following schemes have been used:

A. Directional overcurrent

B. Frequency supervised overcurrent

C. Distance protection

D. Voltage supervised overcurrent

E. Breaker auxiliary contacts scheme with overcurrent

The specific protective function used depends on the application and relay engineer’s preference.

3.3.5.5 Overexcitation

Industry standards state that generators should be operated at rated kVA, frequency, and power factor at any voltage not more than 5% above or below rated voltage. When operation occurs outside these limits, thermal damage is possible on the generator if continued. Overexcitation is one of these abnormalities that can be monitored and protection can be provided.

Overexcitation occurs when the ratio of the voltage to frequency (volts/hertz) applied to the terminals of the generator exceeds 1.05 per unit or 105%. When this volts/hertz ratio is exceeded, saturation of the magnetic core of the generator (as well as any connected transformers) can occur.Stray flux also can occur in non-laminated components, which are not designed to carry this magnetic current. Excessive interlaminar voltages between stator core laminations can occur at the ends of the core and cause overheating. Field current also can become excessive if the excitation system regulator does not operate correctly.

If the overexcitation is allowed to continue, the interlaminar insulation will eventually become overheated and break down, causing damage. Ultimately this could lead to an electrical fault.

Causes of overexcitation include the following:

A. Operating the generator under regulator control at reduced frequencies during startups and shutdowns

B. Complete load rejection, which leaves transmission lines connected to the generator

C. Excitation system failure

D. Loss of voltage transformer signal to the regulator, causing it to go to maximum boost

Protection used to detect this condition is the volt per hertz protective function. One or more are used to protect this ratio from becoming excessive (i.e., greater than 105%).

3.3.5.6 Unbalanced Current

Several system conditions can cause unbalanced currents in three-phase systems and be potentially damaging to generators. These are:

- Untransposed lines
- Unbalanced loads
- Unbalanced system faults
- Open phase conditions

This abnormal condition leads to negative-phase-sequence components of current being produced. In turn, double-frequency current is induced in the surface of the generator rotor, the retaining ring, the slot wedging, and, to some degree, the field winding. These currents can quickly cause thermal failure, depending on the current levels.

The generator's ability to withstand unbalanced currents is specified in ANSI C50.12 and ANSI C50.13. The magnitudes are given in terms of negative sequence values (I_2). There are two ratings given, the I_2 continuous capability, and the short time capability $(I_2)^2t$.

Protection is provided by either negative sequence protective functions or, in some smaller units, unbalanced current. Negative sequence current function is more sensitive and is the preferred method. Most modern digital protection systems use this approach as part of the package of multifunction functions.

3.3.5.7 Loss of Synchronism (Out of Step)

This abnormal operation occurs when the generator loses synchronism with the power system or with other generators it is connected to. Low voltage, reduced or loss of excitation, and some switching operations can cause of the generator to lose synchronism.

Depending on the size of the generator and its application (i.e., direct connected versus unit connected), the loss of excitation function may provide some level of protection. Typically, for large utility unit connected generators, several forms of impedance protection are provided for dedicated loss of synchronism protection.

Loss of synchronism can place severe torsional stress on the hydrogenerator shaft. This can lead to loss of fatigue life. Ideally, the generator should be tripped during the first half slip cycle of a loss of synchronism condition.

3.4 Stator Ground Fault Protection

Conventional ground fault protection only provides coverage of about 95% of the stator winding. This is because the remaining 5% of winding closest to the neutral does not generate enough fault current or voltage to be detected by conventional ground fault protective devices.

To obtain 100% coverage of the stator winding, the following commercially available, supplemental protection schemes can be used:

A. Low-resistance grounded generators. A directional overcurrent relay is connected to receive differential current in its operating coil circuit and neutral current in its polarizing circuit. The relay is set so that it is restrained for external faults but will trip quickly on internal ground faults.

B. High-resistance grounded generators. During a ground fault near the neutral of the generator, the third harmonic voltage at the neutral will decrease and the third harmonic voltage at the generator terminals will increase. Using this phenomena, sensitive ground fault protection of the remaining 5% of the stator winding can be provided using one of the following methods:

1. Third harmonic neutral undervoltage technique. An undervoltage relay monitoring the third harmonic neutral voltage is used to detect ground faults near the generator neutral.

2. Third harmonic terminal residual voltage technique. An overvoltage relay monitoring the third harmonic terminal voltage is used to detect ground faults near the generator neutral.

3. Third harmonic comparator. A voltage differential relay is used to compare the ratio of third harmonic voltage between the terminal and the neutral. A fault will cause the ratio to change and allows the relay to detect the fault.

Another method is voltage injection. This is applied if the generator does not generate sufficient third harmonic voltage to apply any of the above techniques. In this method, voltage is injected into the neutral and the resulting neutral current is monitored. During a fault, the neutral current increases and the relay operates.

3.5 Condition Monitoring

Turbines in hydroelectric power plants must be able to withstand stresses that they are not normally subjected to as a result of rapid starts and stops, and partial loading. These stresses induce fatigue that accumulates and eventually leads to damage. Using the right condition monitoring systems and methodology will avoid these failure modes and help predict the following cases:

A. Wicket gate linkage snaps

B. Cavitation

C. Blade and shaft cracks

D. Bearing rub, fatigue, and overload

E. Insufficient bearing lubrication

F. Mechanical unbalance or misalignment

G. Seal and discharge ring distortion

An effective condition monitoring program is essential to the successful implementation of a condition based or predictive maintenance strategy.

Condition monitoring is also useful for a time-based, preventive maintenance strategy. Depending on the level of condition monitoring, the number of tests that need to be carried out at each dismantle may be reduced.

Condition monitoring can also be used to target the maintenance and inspection activities that need to be carried out at each dismantle.

3.5.1 Commercially Available Condition Monitoring Systems

The following types of condition monitoring systems are commercially available. A brief description and their typical application are provided:

3.5.1.1 Generator Temperature Sensors

Generator temperature is a leading cause of stator winding insulation failure. High temperatures cause insulation to deteriorate at an increased rate. Generator temperature monitoring in salient pole hydroelectric generators is usually performed by measuring the temperature in the stator slots using imbedded RTDs or thermocouples in the air cooler inlet and outlet, and in the cooling water inlet and outlet (if applicable).

A. Rotor pole temperature sensors. Rotor inter-pole connections are a leading cause of failure in salient pole generators. These connections are subject to mechanical stress caused by the relative movement of the poles as well as machine vibration. Failure of an inter-pole connection will result in an open circuited rotor winding. This is a loss of field condition. Advance warning of rotor pole connection failures can be detected by monitoring the temperature of the inter-pole interconnections. Rotor pole temperature monitoring is implemented using a pyrometer mounted on the stator frame. Rotor winding voltage and current is also measured.

B. Air gap monitors. Large salient pole hydroelectric generators have a flexible rotor and stator assembly when compared to round rotor generators. The rotor and stator assembly can become distorted (out of round) or move off-center. It is important to ensure that the air gap is maintained at a minimum separation. Changes to the air gap will cause vibration and in the worse case, rubbing damage to the stationary and rotating parts of the generator. Air gap monitors consist of capacitive sensors mounted around the bore of the stator to measure the average, minimum and maximum distances between the rotor and the stator.

C. Partial discharge detectors. Partial discharge detectors are used to sense partial discharge activity in stator insulation. Early partial discharge detectors consisted of high frequency current transformers placed at the generator neutral or between the terminal surge capacitors and ground. Modern partial discharge detectors consist of capacitors installed at the generator phase terminals. Partial discharge monitoring is typically applied to generators rated 2.3 kV and above. Stator slot couplers are also used to provide more accurate detection and location of partial discharge activity. These sensors consist of strip antennae installed under the wedge or between the top and bottom coils of the stator bar. Sometimes RTD's wiring is used as stator slot couplers but this is not a preferred option.

D. Bearing vibration sensors. Bearing failure is a leading cause of generator losses. Bearing vibration monitoring is widely used on generators to detect bearing problems. Bearing vibration monitoring can also be used to detect problems such as rotor ground faults or rotor shorted turns.

E. Stator frame vibration sensors. Vibration of the stator core and frame can cause mechanical damage to the stator winding insulation. Vibration of the stator core and frame in large salient pole hydroelectric generators is generally caused by poor or deteriorating generator frame supports or an uneven air gap. Stator frame vibration sensors are mounted on either the stator core or the stator frame to detect when excessive stator frame vibration is present.

Condition monitoring systems are not able to detect all failure modes. Therefore it is important to take the opportunity to inspect the machine anytime the machine is opened for other purposes and not to rely wholly on condition monitoring data.

3.6 Routine Spares

The following are common routine spares for hydroelectric power equipment. Store and maintain the routine spares per original equipment manufacturer recommendations to maintain viability. Refer to Data Sheet 9-0 for additional guidance.

- Generator core segments, stator bars and poles
- Water turbine bearings, vanes, wicket gates and links

4.0 REFERENCES

4.1 FM

Data Sheet 4-0, *Special Protection Systems*
Data Sheet 4-5, *Portable Extinguishers*
Data Sheet 4-11N, *Carbon Dioxide Extinguishing Systems*
Data Sheet 5-4, *Transformers*
Data Sheet 5-11, *Lightning and Surge Protection for Electrical Systems*
Data Sheet 5-12, *AC Generators*
Data Sheet 5-19, *Switchgear and Circuit Breakers*
Data Sheet 5-20, *Electrical Testing*
Data Sheet 5-23, *Design and Protection for Emergency and Standby Power Systems*
Data Sheet 5-31, *Cables and Bus Bars*
Data Sheet 5-40, *Fire Alarm Systems*
Data Sheet 5-48, *Automatic Fire Detection*
Data Sheet 7-32, *Ignitable Liquid Operations*
Data Sheet 7-88, *Storage Tanks for Ignitable Liquids*
Data Sheet 7-98, *Hydraulic Fluids*
Data Sheet 9-0, *Asset Integrity*
Data Sheet 13-3, *Steam Turbines*
Data Sheet 17-4, *Monitoring and Diagnosis of Vibration in Rotating Machinery*

4.2 Others

Dawson, C. W. (Aluminum Company of Canada, Ltd). "Fire Detection in Open-Type Hydrogenerators." *IEEE Transactions on Power Apparatus and Systems.* 1970.

Institute of Electrical and Electronic Engineers (IEEE). *IEEE Guide for AC Generator Protection.* IEEE C37.102.

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Institute of Electrical and Electronic Engineers (IEEE). *Recommended Practice for Insulation Testing of AC Electric Machinery with High Direct Voltage.*IEEE 95.

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APPENDIX A GLOSSARY OF TERMS

FM Approved: Reference to ''FM Approved'' in this data sheet means the product or service has satisfied the criteria for Approval by FM Approvals. Refer to the *Approval Guide*, a publication of FM Approvals, for a complete list of products and services that are FM Approved.

For additional terms, refer to Appendix C.

APPENDIX B DOCUMENT REVISION HISTORY

The purpose of this appendix is to capture the changes that were made to this document each time it was published. Please note that section numbers refer specifically to those in the version published on the date shown (i.e., the section numbers are not always the same from version to version).

January 2023. Interim revision. Minor editorial changes were made.

July 2020. Interim revision. Updated contingency planning and sparing guidance.

October 2016. This document has been substantially revised to bring it up to date with current maintenance, testing, and operating practices. The following major changes were made:

A. The use of water spray and carbon dioxide extinguishing systems for the protection of generators has been clarified, including design and installation considerations related to fire detection, interlocks, fire protection system design, and reference to other data sheets.

B. Water mist and hybrid (water and inert gas) extinguishing systems have been added as options for the protection of generators.

C. The document has been reorganized to provide a format that is consistent with other data sheets.

D. References to “flammable” and “combustible” liquids have been replaced with “ignitable liquids” throughout the document.

April 2012. Terminology related to ignitable liquids has been revised to provide increased clarity and consistency with regard to FM Global’s loss prevention recommendations for ignitable liquid hazards.

May 2010. This data sheet was substantially revised to bring it up to date with current maintenance, testing and operating practices.

December 2009. The electrical section of this Operating Standard was completely revised.

May 2008. Appendix D, NFPA Standards, was updated.

January 2006. Revised recommendations for fire protection for enclosed generators 100 MVA and larger and for generators from 50 to less than 100 MVA if a serious exposure exists due to business interruption, added a section on generator fire protection describing CO_2, water spray and water mist, added a section describing generator fire testing and fire hazards.

January 2004. Changes to recommendation 2.4.3 for protection of air-cooled generators.

January 2000. This revision of the document was reorganized to provide a consistent format.

APPENDIX C SUPPLEMENTARY INFORMATION

C.1 Description of a Typical Hydroelectric Generating System

The general arrangement of the major components of a typical hydroelectric generating system is shown in Figure 2.

The bulb, axial flow-type (sometimes called tube-type), and pump-storage turbines are described in detail in this section. The various kinds of turbines that provide the motive power (Francis reaction-type turbine, Kaplan and propeller-type turbines, and Pelton impulse turbine) are briefly described.

The turbines are generally used to drive an electric generator, but occasionally they have been employed to power a log grinder in a paper mill or drive a line shaft.

The Institute of Electrical and Electronic Engineers (IEEE) Standard 492, *Guide for Operation and Maintenance of Hydro Generators,* is the basic reference for information pertaining to the operation, loading, and maintenance of hydrogenerators and generator/motors (pump-turbines).

Draft tube: A tapered conical tube with flared end or an elbow-shaped tube that conducts the water after passing through the runner to the rail race. See Figure 2.

Francis turbine: The Francis turbine is a reaction-type turbine where the water under pressure is only partly converted into velocity before it enters the turbine runner (Figure 3). This is an inward flow turbine where water enters a spiral-shaped case from the intake passages or penstocks, passes through the stay ring, and guided by stationary stay ring vanes passes through movable guide vanes (wicket gates), then through the runner and into the draft tube and exits into the tail race. The movable guide vanes control the flow of water to the runner which in turn controls the power output of the turbine. These turbines are used for medium heads ranging from 50 ft (15 m) to 1600 ft (480 m). Some of the earlier installations for heads under 40 ft (12.1 m) and small power outputs used Francis turbines in a vertical open flume setting as illustrated in Figure 4. The turbine is entirely submerged in an open chamber and the water surface is exposed to atmospheric pressures.

Impulse turbine: Commonly known as a Pelton turbine, consists of one or more force jets of water discharging into an air space and impinging on a set of buckets attached around the periphery of a disc (see Figure 5) The buckets of the modern Pelton turbine are double discharge ellipsoidal-shaped bowls withsharp center splitters. The latter divides the jet of water into two smooth streams which escape in a direction opposite to the movement of the runner bucket. The velocity of the exiting water is reduced to practically nothing and falls by gravity into the tail race. The size of the jet is controlled by the nozzle opening which determines the power output of the turbine. The impulse turbine is usually used for heads between 400 ft (122 m) and 600 ft (1828 m).

*Kaplan turbine:*A propeller turbine in which the runner blades are unshrouded, that is, it has no crown or band like on the Francis turbine (see Figure 6). The blades may be from three to eight in number and are adjustable. The blades may be adjusted mechanically by hand, or by an electric motor through a train of gears or by oil pressure. The water passages to the turbine are arranged the same as in the Francis turbine and the flow of water through the passageways is the same. The limiting head for the Kaplan turbine is about 150 ft (45.7 m) except some small units can be used for heads up to 240 ft (73.1 m).

Crossflow turbine: Impulse-type machine made by Ossberger Turbine Fabrik Company in Germany from whom they get the name ”Ossberger Turbine.” The largest runner made for these machines is 4 ft (1.2 m) in diameter and the allowable head ranges from 20 to 600 feet (6 to 181 m). These units require more floor space than the horizontal type but the structure is less complex. Runners are self-cleaning and free from cavitation but are susceptible to wear if there is excessive silt or sand in the water. In general, maintenance is less complex than that required by other units.

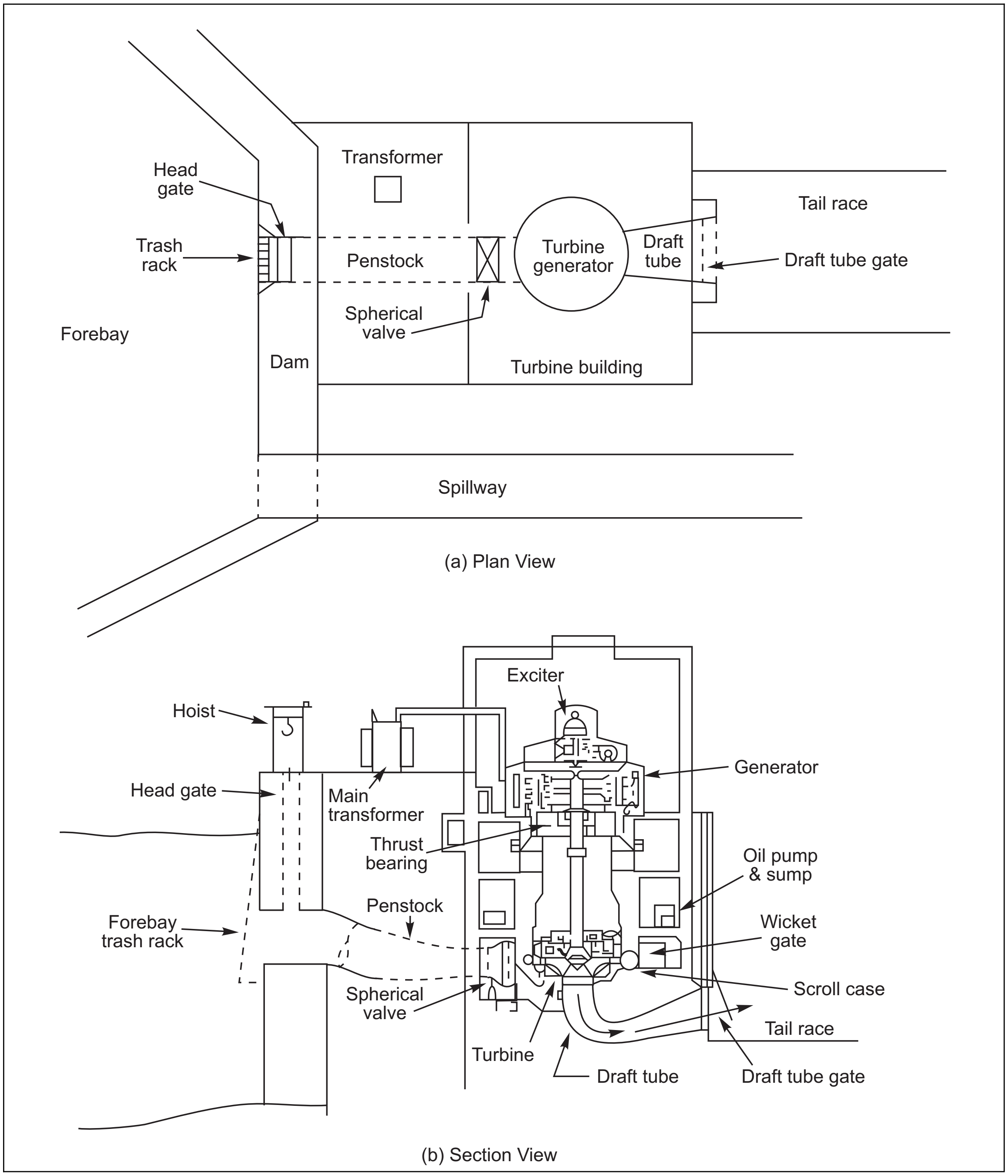

Fig. 2. Arrangement of major components of typical hydroelectric generating station.

Penstock: A metal or concrete conduit to conduct water from the headgate or forebay to the turbine. See Figure 2.

Propeller turbine: The propeller turbine is a reaction-type unit that has a runner that resembles a ship's propeller. The blades may be fixed to the runner at a predetermined angle best suited for the hydraulic and load conditions, or they may be adjustable as in the Kaplan turbine wherein a hydraulic servomotor is provided to rotate the blades to the most efficient position. The Kaplan turbine is usually arranged in a vertical position, but in later adaptations of the propeller turbines, such as the bulb and axial flow types, the shafts are horizontal or inclined.

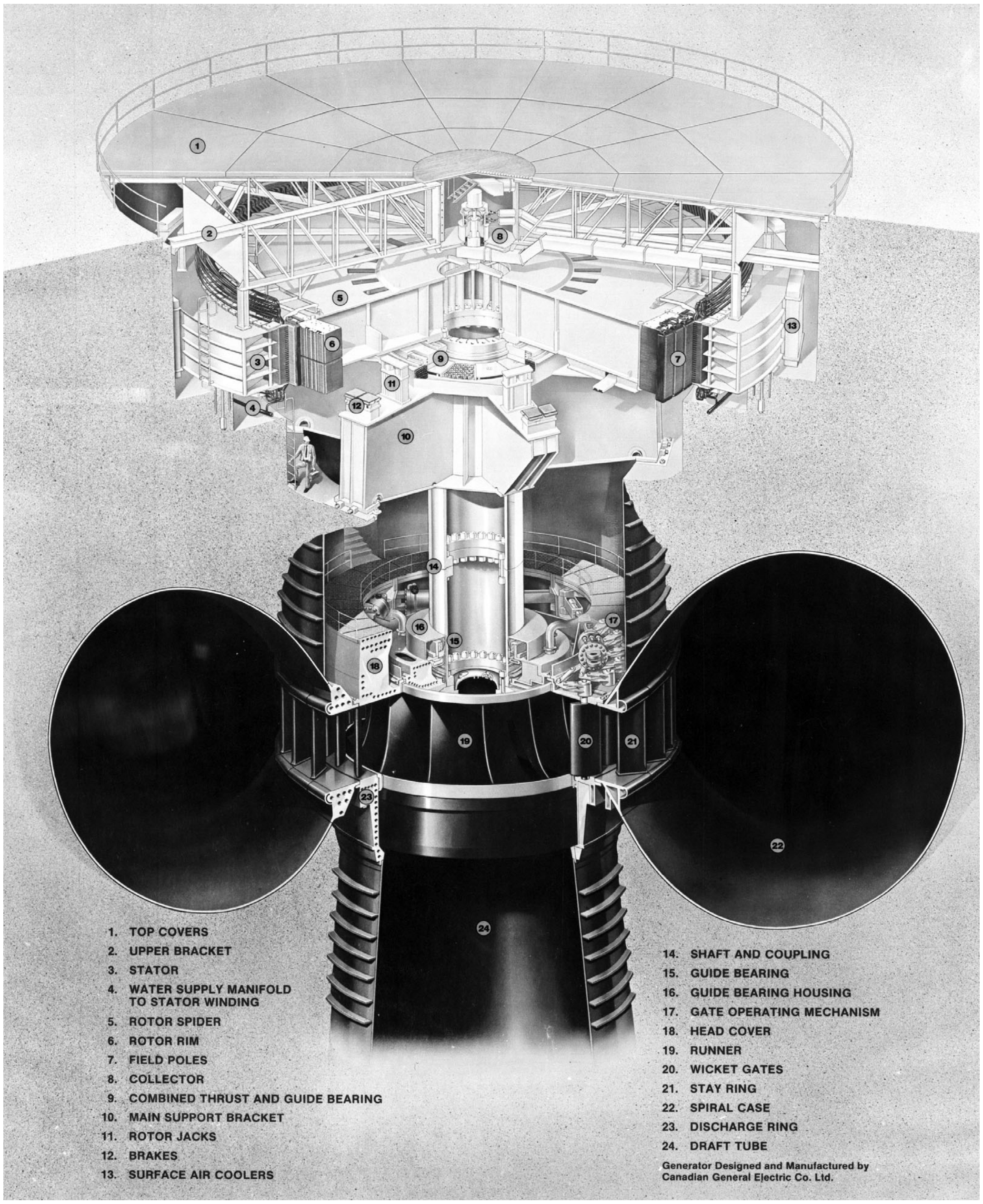

Fig. 3. Francis turbine and generator (Allis Chalmers, Hydro-Turbine Division)

Runner: The rotating part of the turbine that is attached to the main turbine shaft. In the Francis turbine the runner is a "cage-like" rotor consisting of a number of curved blades or vanes fixed radially around the center and partially enclosed by a shroud ring. The upper ends of the blades are attached to a "crown" and the lower ends are attached to a band. In the smallest size the runner may be a one-piece casting although in most cases a separate cast iron nose piece is bolted to the hub.

Servomotor: An oil operated power cylinder that is used to control the position of the runner blades and the wicket gates. They may be actuated manually or automatically by the governor.

Stay ring: That part of the guide apparatus between the spiral case and the wicket gates that contains the stationary stay vanes. This serves as a foundation for the turbine and generator. See Figure 3.

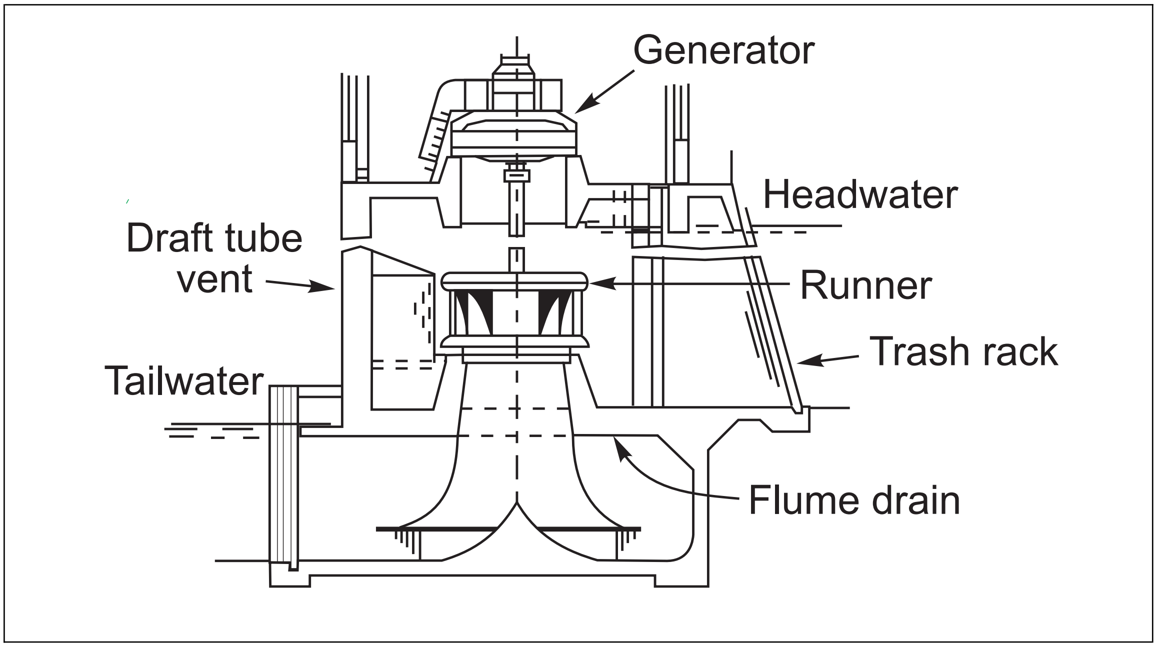

Fig. 4. Open flume setting

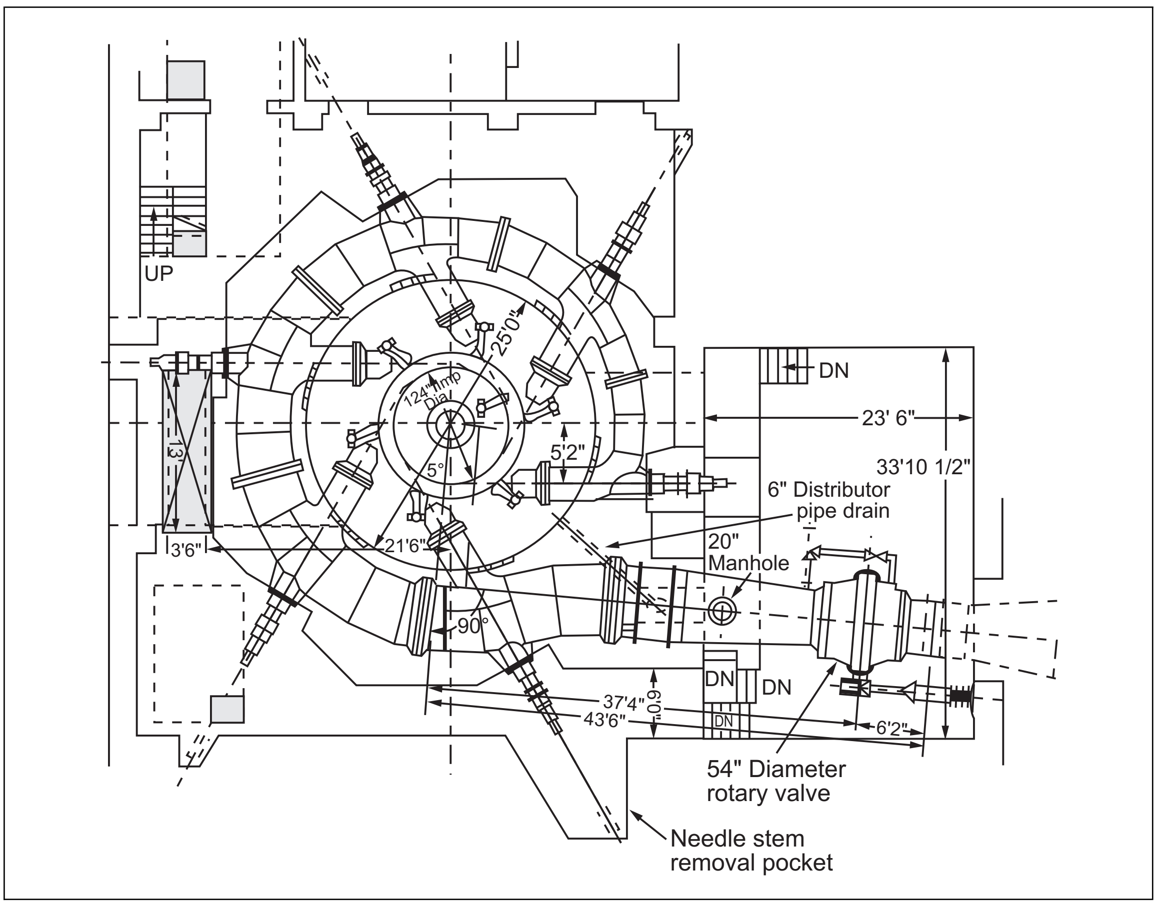

Fig. 5. Plan view of six-jet vertical impulse turbine

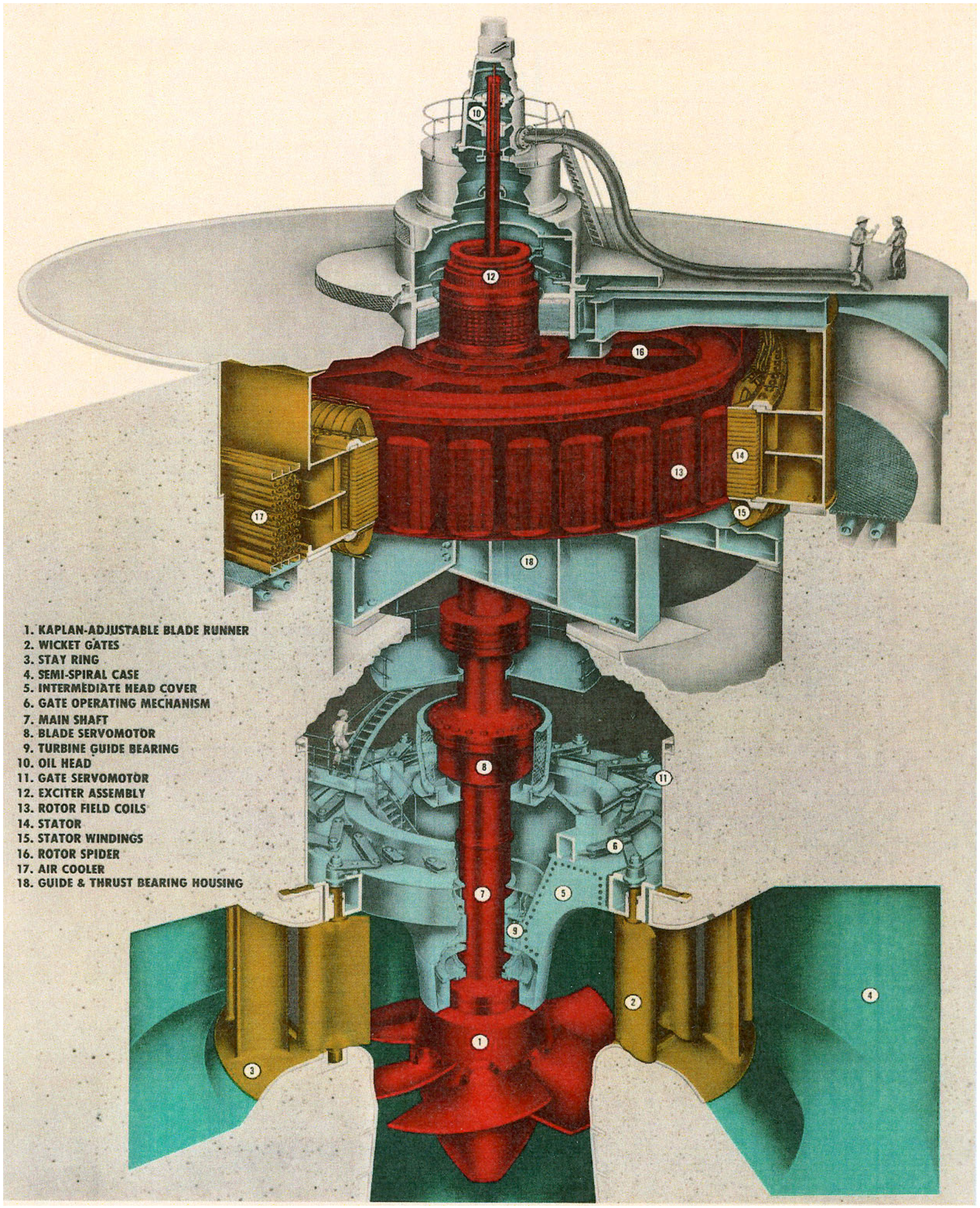

Fig. 6. Kaplan turbine and generator (Allis Chalmers, Hydro-Turbine Division)

Wicket gates or guide vanes: Control the flow of water to the runner. They consist of a number of pivoted guides or vanes arranged to touch each other in the closed position. They are connected to a shifting ring by means of a link that is designed to break when a foreign object becomes fouled in the vanes.

Surge tank: A vertical pipe connected to the water conduit at some point between the intake structure and the turbine to protect against water hammer caused by a sudden change in rate of water flow.

Trash rack: A steel structure consisting of parallel vertical steel bars spaced from 2-1/2 in. to 5 in. (5 to 10 cm) apart, depending upon the size of the turbine, installed at the water intake to prevent the entrance of foreign material that may damage the turbine. See Figure 2.

Axial-flow Kaplan turbine: A later, more economical development to replace the open flume and concrete spiral settings. It is designed with the runner on a horizontal or inclined shaft installed in the waterway, which is straight through or slightly slanted from intake to discharge (Figures 7 and 8).

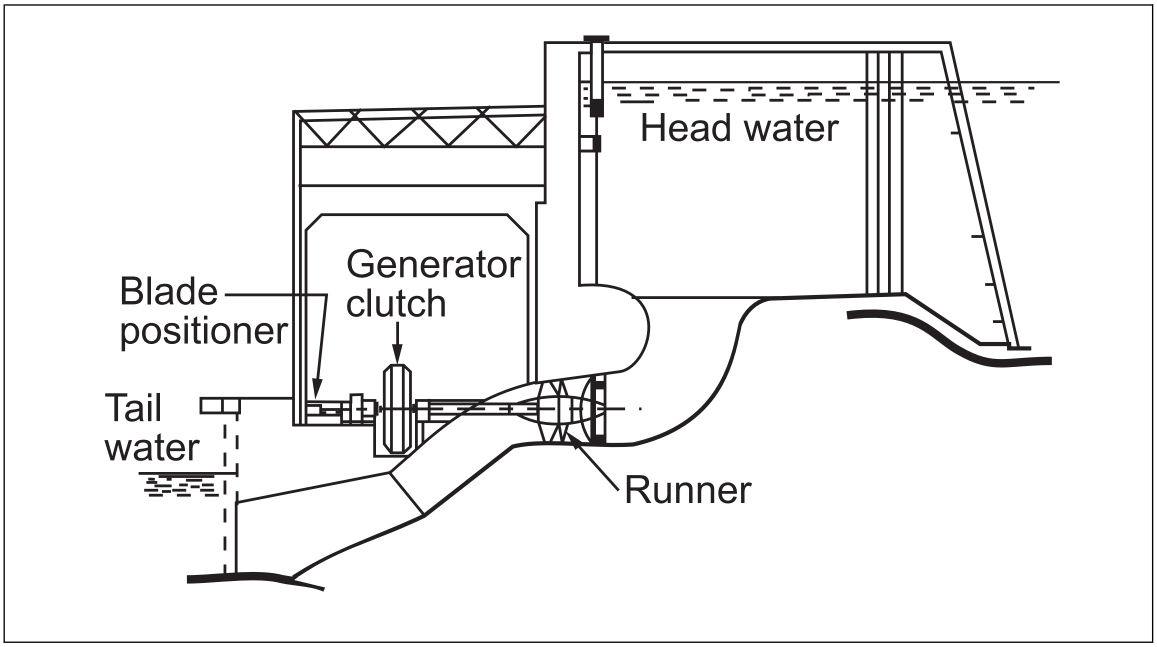

Fig. 7. Axial-flow turbine-runner on horizontal shaft

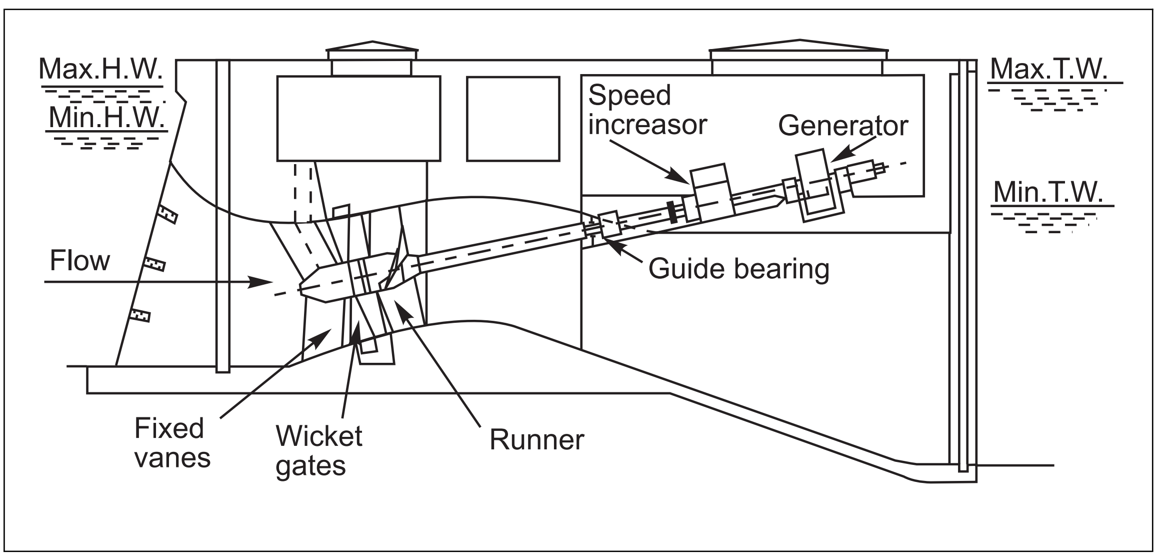

Fig. 8. Axial-flow turbine-runner on inclined shaft

This type of installation eliminates the spiral case and elbow-shaped draft tube and much of the construction that is required with the conventional vertical turbines. The resulting savings in construction costs makes it feasible to rebuild these low head or low capacity facilities that were previously considered to be uneconomical. Standardized tube turbines (as described below) are currently available from domestic manufacturers in capacities up to 700 kW and for heads up to 60 ft (18.1 m).

These axial-flow Kaplan turbines are suitable for use at heads up to 100 ft (30.3 m) and for tidal facilities where the turbine is designed to operate a turbine with the water flowing in either direction.

Axial-flow propeller turbines are available in four different arrangements:

1. The rim-type turbine, whose generator rotor is mounted on the periphery of the turbine runner blades. It was developed about 40 years ago in Switzerland and is called the Straflow. A total of 75 units are still in service. The units have fixed blade runners. Difficulties have been encountered with sealing the large diameter gap between the generator rotor and turbine waterway, which has resulted in frequent outages and excessive maintenance costs. A new seal design has been developed that will permit runners up to 32 ft (9.7 m) and 130 ft (39 m) head.

2. The pit-type, whose generator is in series with the turbine runner and is enclosed in a submerged watertight housing which may also include a speed increaser.

3. The tube-type has some advantages over the bulb-type due to the absence of a pit or a bulb obstructing the waterway and the generator being more accessible.

4. The bulb-type, whose generator is enclosed in a streamlined watertight steel capsule installed in the waterway either on the upstream or downstream side of the runner (Figure 9).

Bulb-type turbines: The bulb units with a straight tapered draft tube have been found to be superior in both operation and efficiency to the elbow draft tube associated with conventional machines. For the same head and output the diameter of the runner of a bulb machine is 15% to 20% smaller than other Kaplan units. This reduction in runner size results in about a 10% savings in the electromechanical assembly as compared to a conventional set, even though the bulb turbines are more expensive to produce.

Considerable savings are also affected in structural costs due to the shallower excavations required because of the absence of the draft tube elbow. A lower superstructure is required because the overhead crane must lift only a distance equal to the diameter of the runner instead of the combined height of the runner, shaft, and generator that is necessary in a conventional installation. The bulb units are also less sensitive to cavitations than a vertical Kaplan unit.

Due to the almost symmetrical form of the upstream and downstream flow passages, the bulb units are fully reversible. Tidal power stations constructed with the bulb units operating with the flow in either direction are considered peak power facilities.

The bulb-type turbines have an excellent performance record. Maintenance of the guide and thrust bearings, turbine shaft seal, oil pumps, cooling fans, and leakage evacuation pumps are said to present no more problems than do the conventional units and the runner blades and hub, blade servomotor, and the oil distribution head assembly are the same as for a conventional machine.However, the limited accessibility to the bulb may cause some difficulty in servicing procedures and they are more time consuming.

Problems in the generator are no more likely to occur than in a vertical unit and the probability of major breakdowns occurring is small.

Many of the repairs, such as replacement of the following items, can be made inside the bulb units without shutting off the flow:

- Alternator guide bearing shells and slingers
- Turbine guide bearing shells and slingers
- Thrust bearing pads and slingers
- Runner seal components
- Rotor pole shoes
- Isolated stator bars
- Rotor rings
- Ancillary equipment such as fans and pumps

Diagonal-flow Kaplan turbines differ from the vertical shaft propeller turbine in that the axis of the blades of the propeller runner is at an angle of 45° with the main shaft instead of being at right angles to it (Figure 10). The blades may be fixed or adjustable. If they are adjustable, the unit is called a Dariaz turbine. The wicket

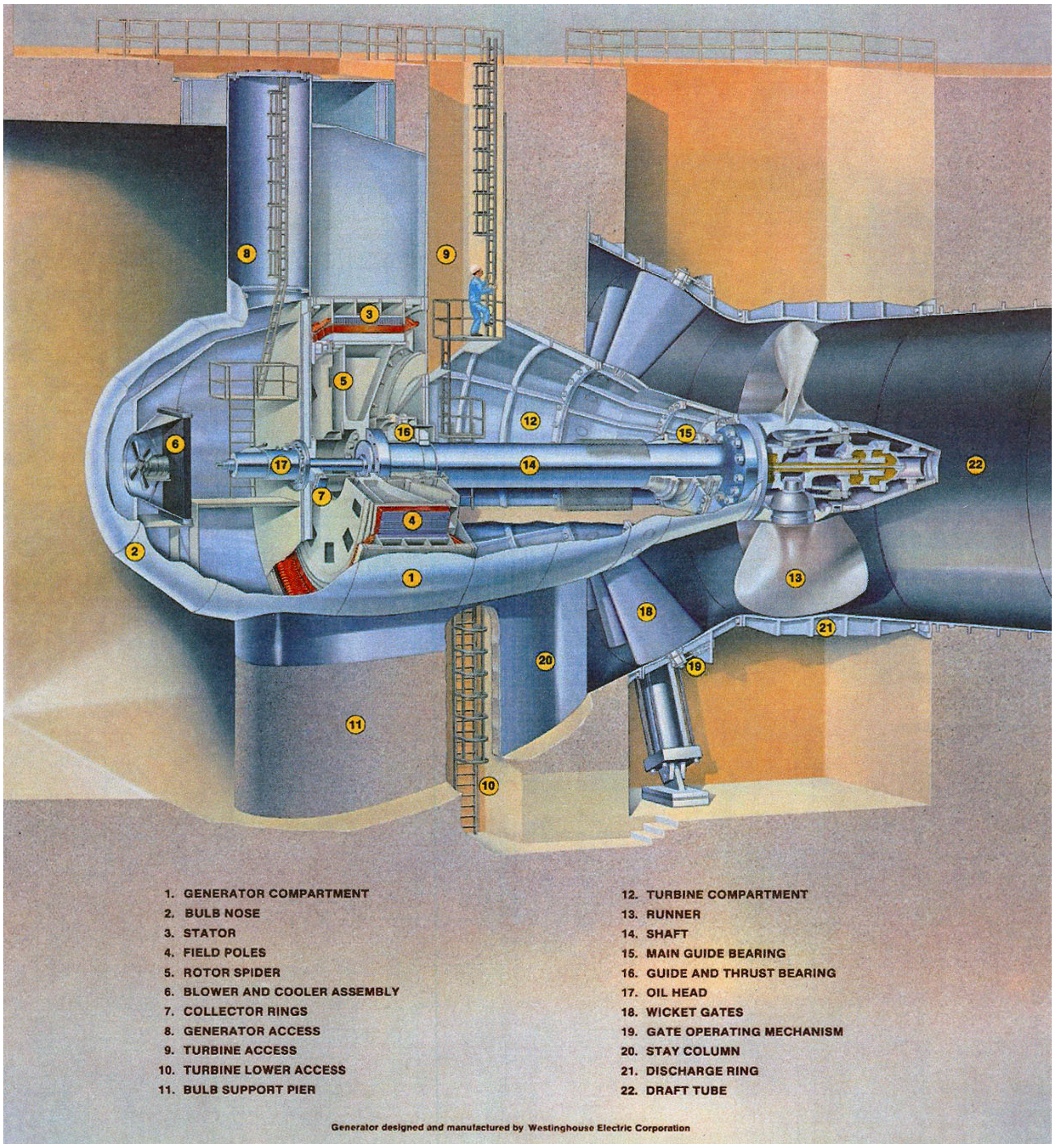

Fig. 9. Bulb-type hydraulic turbine and generator (Allis Chalmers, Hydro-Turbine Division)

gates are also set at an angle of 45° and the spiral case is at the same angle. Some adjustable-blade diagonal-flow runners are made so that the blades can be closed together to shut off the flow of water and eliminate the need for wicket gates.

Pump storage units: Besides the conventional hydroelectric facilities, another type of hydro facility is the pumped-storage unit (Figure 11) which is available in sizes ranging from 500 hp (373 KW) to 300,000 (224 MW) hp and heads up to 1200 ft (366 m). This type of facility is similar to a standard hydroelectric facility except the generator is motorized, and the turbine is used as a pump to return water to an upper level storage area. In this type of operation the generator is used during peaking hours when the power is needed. During off-peak hours it is operated as a synchronous motor driving the water turbine as a pump to fill a reservoir. When the unit is not generating or pumping, it can also be operated as a synchronous condenser for power factor improvement. After the turbine is brought up to speed as in generating, the wicket gates are closed and the tail race water depressed with compressed air. The generator breaker is then closed and the reactive power output can be adjusted as required.

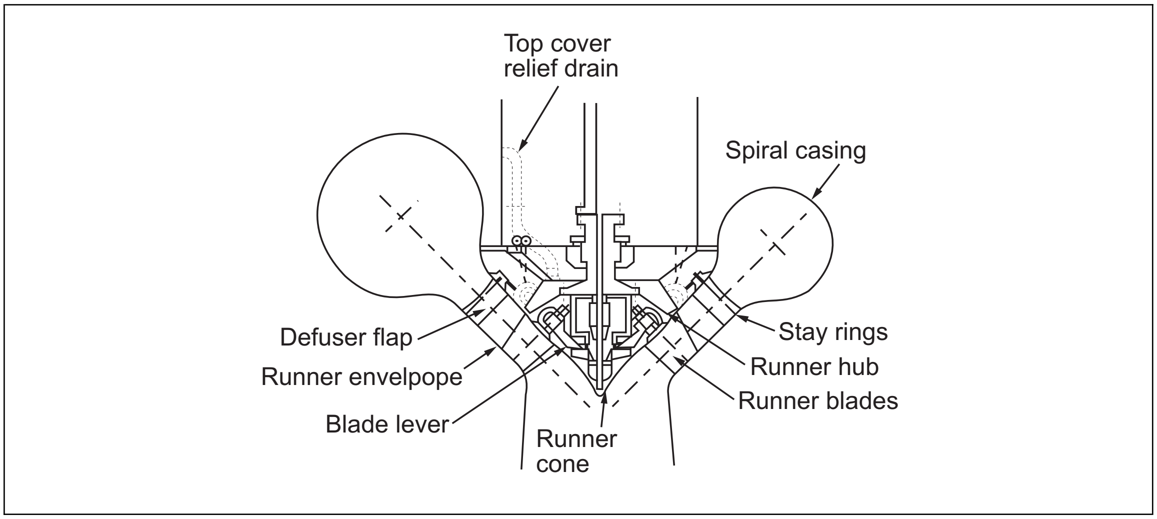

Fig. 10. Sectional elevation of diagonal-flow (Dariaz) turbine

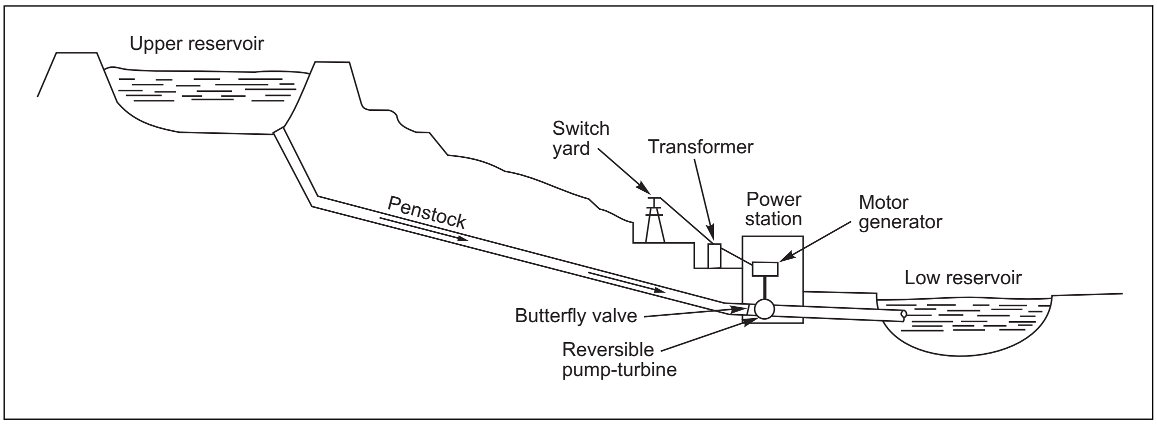

Fig. 11. Pumped-storage arrangement

In all cases pumps would be started with the tail water pneumatically depressed below the runner and with the outlet spherical valves closed. Water, in the draft tube of the pump-turbine being started, is lowered by compressed air.

The generator, being the driving unit for the pump, is operated as a synchronous motor (Figure 12). Starting torque for the generator-motors can be provided by a small “house” turbine-generator or a direct connected impulse turbine for each unit. Excitation is applied to the generator motor fields from static exciters.

Each facility being built for pumped storage operation may have a new design with unique features that should be carefully reviewed. Larger units of over500 MW may have the generator-motor water cooled. Load-break switches and reversing switches at generator voltage are a necessity for any synchronous starting scheme. Some of the smaller units of the 200 MW size may have manual reversing.

Water turbines intakes: The water intake to every hydroelectric facility is usually known as the forebay and its purpose is to act as a storage reservoirto supply water to the penstock or conduit under controlled conditions as the load is increased and to store water when the load is reduced.

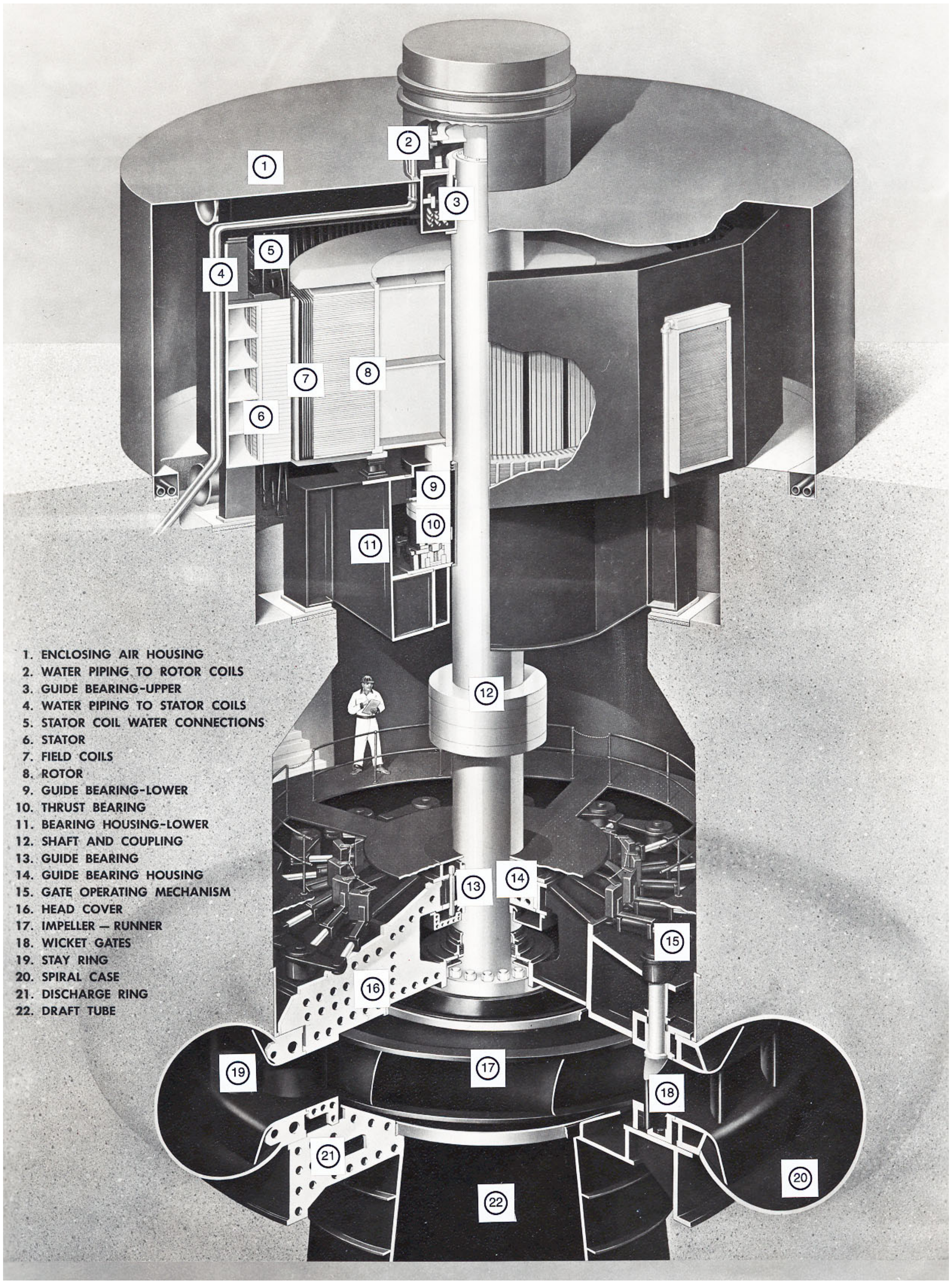

Fig. 12. Reversible pump/turbine-generator unit; upper section: generator- motor; lower section: Francis-type reversible pump/turbine (Allis Chalmers, Hydro-Turbine Division)

Forebay equipment will usually include the following:

- Trash racks
- Ice removal system
- Penstock closing gates, ventilators, hoists, and stop logs
- Spillway
- Water-level gages
- Telephone system

In cold climates special arrangements are needed to prevent ice from blocking the intake. There are three methods commonly employed to accomplish this: (1) heating the racks, (2) diverting the ice with compressed air jets, or (3) removing the racks during 3frazil3 or anchor ice runs. The latter should never be done if there is danger of sheet ice or heavy trash entering the penstock. Frazil or anchor ice is one of the greatest sources of trouble due to its tendency to adhere to the racks and turbines when they have a temperature equal to or less than the freezing point of water. A means of closing off the penstocks at the forebay to shut off the flow of water in an emergency or for inspections and repairs must be provided. This is accomplished by means of a number of different kinds of intake gates and valves depending upon the intake pressure. For low-pressure intakes, plain sliding gates, wheel gates, caterpillar gates, stoney gates, and taintor gates are used. For high-pressure intakes, caterpillar gates, butterfly valves and cylinder gates are usually employed. Air inlets are provided at the intake structure to prevent collapse of the penstock if the headgate is closed and the conduit is suddenly drained. High points in the conduit may also require the installation of an air outlet valve to prevent the line from becoming air bound.

Bearings and lubrication: Most vertical-type turbine-driven generating units are provided with one or more guide bearings and a thrust bearing. The guide bearings are water lubricated or oil lubricated. Water-lubricated bearings are found in most of the older installations, but the modern installations employ oil-lubricated bearings with Babbitt metal, the lubricating pumps being driven by the main shaft or by separate electrical motors. The guide bearings for vertical shaft settings may also be self-lubricated by means of the oil being circulated by rotation of the main shaft without the use of separate pumps.

Where water-lubricated bearings are operated entirely submerged, as in open- flume construction, no other lubrication is required, although grease is sometimes used in addition.textSpecial plastic bearings are being used in some cases as a substitute for lignum vitae bearings, which have been used in the past in small hydroelectric facilities. Experience has shown that this plastic will outlast by many years the lignum vitae bearings, which must be replaced every two years.

Special plastic bearings are being used in some cases as a substitute for lignum vitae bearings, which have been used in the past in small hydroelectric facilities. Experience has shown that this plastic will outlast by many years the lignum vitae bearings, which must be replaced every two years.

Brakes and jacks: Depending upon the size of the vertical-type units, brakes may be mounted singly or in pairs on support brackets installed around the top edge of the turbine pit. There may be 12 to 16 brakes mounted in pairs on the main support brackets. These are designed to operate at 100-125 psi (690- 862 kPa) air pressure by pressing against a brake plate on the bottom of the rotor rim, or they may also be used as a jack to raise the rotor by increasing the pressure.

In general, brakes may be applied continuously when the speed has dropped to about 50% of normal and the generator is without field excitation.Destructive heating will result if the brakes are applied at runaway speed or if the wicket gates cannot be fully closed.

A combined brake and jack may be used on a very large generating unit. The brake shoes are provided with a renewable molded friction wearing surface.

The brake control system is designed for automatic and manual operation and is tied in electrically with the generator starting or stopping sequences. Application of the brakes is controlled by an adjustable speed switch that closes on deceleration at a preset point and actuates the solenoid brake valve in the turbine actuator cabinet. Limit switches on the brakes are electrically connected with the generator starting sequences so the unit cannot be started unless the brakes are released.

Spacing blocks are also provided for blocking the rotor in the fully raised position, which permits easy inspection or removal of the thrust bearing.

Overspeed design: The speed of a hydroelectric turbine is normally designed to be as high as possible. The higher the speed, the smaller and lessexpensive will be the turbine. Likewise, the generator will be more efficient and less costly. However, with the high speeds there may be more mechanical problems.

The specific speed (N_s), also called characteristic speed, is used as a common basis of comparison for all turbines. This is because turbine runners of different types have widely varying characteristics of power, speed, dimensions, and operating head. Any given runner has a definite horsepower at1 ft (0.3 m) head and a definite speed at which it is most efficient. Each type and design of runner will have a given Ns independent of the size but characteristic of the shape or geometry. This value is used in selecting a runner for a given set of conditions of head, horsepower, and speed.

By definition, specific speed is the number of revolutions per minute a runner will revolve if it were so reduced in proportion that it would develop 1 hp (746 W) under 1 ft (0.3 m) head.

The specific speed for a given wheel is calculated from data obtained by test by means of the following formula.

$$N_s = \frac{N\sqrt{P}}{H^{5/4}}$$

Where N_s = Specific speed
N = Rpm at gate and head H
P = Horsepower per runner
H = Head in feet

Runaway speed: If a turbine runner is allowed to revolve freely without load and with the guide vanes wide open, it will overspeed to a value called the runaway speed. The runaway speed of a turbine at normal head varies with the specific speed and is expressed as a percentage of normal operating speed.Francis turbines range from about 170% at low specific speed to 195% at high specific speed. For propeller turbines the runaway speed varies with blade angle; the steeper the blade angle, the lower the runaway speed. For fixed-blade propellers with blades set at 16-20 degrees (where maximum efficiency is usually obtained), the runaway speed is about 255 to 235 percent, respectively.

For adjustable-blade turbines, where the minimum blade angle is sometimes as low as 10-12 degrees in order to obtain high efficiency at low load, the maximum possible runaway speed will be about 290-270 percent, respectively. However, with adjustable-blade propeller turbines, there is, from the standpoint of efficiency, an optimum relationship between runner blade angle and guide vane opening, usually controlled by a cam on the operating mechanism. The higher the gate opening, the steeper the blade angle. Thus the combination of wide open gate and minimum blade angle can occur only in the so called “off-cam” position, which is an extremely rare possibility. Inmost units this maximum possibly “off-cam” runaway speed is reduced by limiting the minimum blade angle to 14-16 degrees.

The overspeed trip device commonly called the “runaway speed limiter” may be connected mechanically, hydraulically, or electrically to the turbine governor to shut off the flow of water to the runner.

The runaway speed for impulse turbines ranges from 180-190 percent of normal speed, depending on the specific speed of the runner per jet. The higher the specific speed, the higher the runaway speed.

For all turbines, if the maximum head is higher than the normal head, the runaway speed will be increased in proportion to the square root of the head. Therefore, runaway speed should be based on the maximum operating head rather than on the normal head. Water turbines and their driven generator should always be designed for the maximum runaway speed that can possibly be achieved.

The ordinary type Francis turbine will reach about 180% of its normal speed at runaway, but should the maximum head increase, for example, to 15% above normal due to heavy rains, the turbine would reach about 193% of its normal speed at runaway. For some fixed blade propeller installations, the maximum runaway speed for which the turbines and generators are built is as high as 21/2 times normal. Once an initial runaway speed test has been conducted and the unit accepted by the owner, additional overspeed tests of the unit are not necessary or advisable. However, a bench test of the overspeed device may be conducted.

Cavitations and water hammer: A serious problem associated with many hydraulic turbines is pitting of the runner blades or draft tubes which is caused by the formation of rapidly whirling water as it flows through the water passage. When the head acting on the water passage is reduced to that of vapor pressure (about 1.25 absolute head at usual water temperature), flashing of the water into vapor occurs. Voids or cavities are produced, causing what are known as cavitations. Slight changes in static pressure or velocity with resultant changes in pressure cause these cavities to form and collapse alternately. This is accompanied by intense local water hammer and high local momentary pressure. When these cavities collapse on the surface of runner blades or draft tubes, the pressure generated tends to enter microscopic cracks and pitting results.

Cavitations are also caused by protrusions such as rivet heads, overlapping joints, or manholes not flush with the draft tube surface; excessive draft heads resulting in a vacuum on runner surfaces; defects on the blade formation due to faulty manufacture; improper design of the runners; and the improper materials used during construction.

Severe cavitations can cause loss of efficiency and excessive vibration. It usually occurs on the back side of the runner blades and, on Francis turbines, can weaken the runner and lead to structural failure.

On Kaplan and other propeller-type turbines cavitations pitting can occur on the bottom side of the blades at the trailing edge near the blade tip.Propeller runners are most susceptible because of their high relative velocity and small blade area.

The resistance to cavitations action by the various types of metals commonly used in turbine runners is shown in Table 6.

Table 6. Resistance to Pitting of Different Runner Materials

Type of Material	*Relative Rate of Loss of Metal Due to Cavitation*
Welded or cast stainless, 18 Cr, 8 Ni Steel	1
Rolled stainless 18 Cr, 8 Ni steel	1.5
Cast stainless 14 Cr, 1 Ni steel	4
0.33 carbon cast steel	8
Manganese bronze	23
Cast iron	50-75

Turbine runners are also subject to corrosion and erosion. Per Table 6, cast iron is most susceptible to corrosion, and stainless steel is the most resistant.

Erosion of the runner and water control equipment is caused by abrasive silts or sand in the water and by operating at light loads for extended periods.

Repairs: Depending upon the material used in the construction of the runners, cavitations damage is usually repaired by welding on new material. The parts of small and medium size water turbines, especially the older units, are usually made of cast iron or cast manganese bronze. These metals are not easily welded, however, and will have to be replaced if damaged. Modern larger units are made of cast or fabricated plate steel which if damaged can be repaired by welding which should be performed only by qualified technician.

Stainless steel bars applied to the underside of the propeller blade along the blade tip are also effective in controlling cavitations damage. Some manufacturers will weld stainless steel in a depression purposely cast in a surface that is most subject to cavitations damage as a preventive measure. The most favorable material to use which has a high resistance to cavitations and erosion from impurities in the water is now considered to be one that contains 12 to 14% chromium with not more than 1% nickel.

While bronze is very resistive to cavitations pitting, its principal disadvantage in comparison to stainless steel is that it cannot be welded. Aluminum bronze containing about 10% aluminum and 1% iron has better resistance to cavitations and in addition has good tensile strength and can be welded.

Note: The use of magnetic surface inspection techniques to check for defects is ineffective for bronze and stainless steel. Liquid penetrant methods should be employed instead.

Governor system: Satisfactory control of a hydraulic turbine depends upon a sensitive governor and an accurate and reliable means of registering turbine speed with the flyball head. Belts and other forms of mechanical drive have not proven sufficiently reliable and require considerable maintenance.

A hydraulic turbine intended to operate only in conjunction with a larger power system will, in many cases, require no speed governor. In this case, only equipment for load control is necessary. If the hydraulic turbine is to feed into a local system or a system that is isolated from a large system, the speed and power of the turbine must be regulated by changing the flow of water to the turbine. A governor senses the speed changes resulting from a load or head change and causes movement of the wicket gates (guide vanes) and/or blade pitch on reaction turbines.

Several types of governors may be found on hydraulic turbine installations. Common governors are the flyweight governor, which is a mechanical device that takes advantage of centrifugal force to tilt flyweights mounted on a plate to control a speed rod; the hydraulic governor which uses a special centrifugal pump instead of flyweights for speed sensing; the mechanical hydraulic governor which uses a flyweight system to control a hydraulic oil system (see Figure 13); the electric governor system which can use a motor drive powered by a transformer in the generator leads or a separate permanent magnet generator and may be used separately or as an electric hydraulic governing system; and, on new units from 5000 KW up, an electronic(analog or digital) governor which offers more reliable speed governing accuracy and stability.

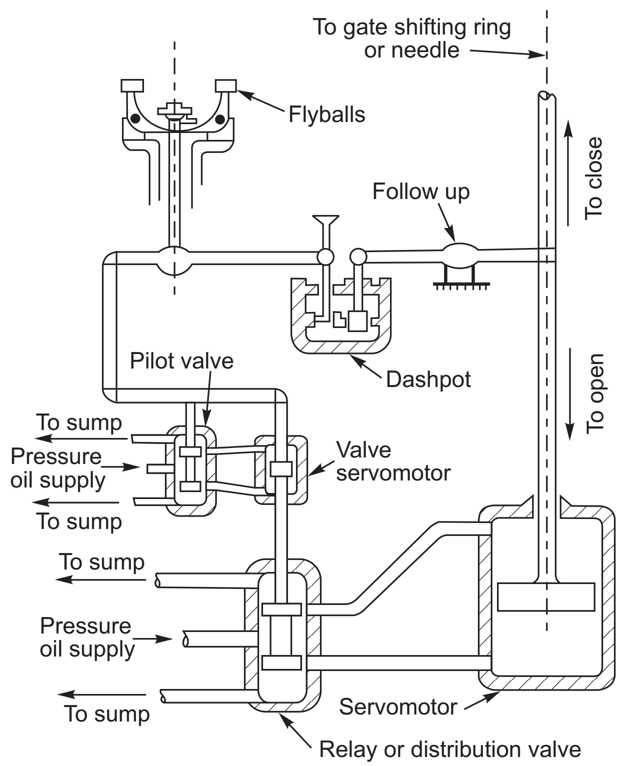

Fig. 13. Schematic diagram of governor

A modern governing system for a hydraulic turbine usually includes the following:

A. Governor head (speed-sensing device)

B. A means for transmitting rotational speed of the turbine to the governor head

C. A hydraulic power system which consists of:

1. A pilot valve and distributing valve hydraulic system

2. Hydraulic servomotors to operate wicket gates, deflectors, or nozzles

3. A hydraulic power source to supply pressurized oil to valves and servomotors

D. A restoring connection between wicket gates, deflectors, or nozzles and the valve system

E. Compensating dashpot (stabilizing device)

The Woodward Cabinet Actuator includes these devices and also may include pumps, pressure tanks, sump pump, connecting piping, and various auxiliary devices in the control system.

Electronic governing system: The permanent magnet generator shown in Figure 14 is employed with an electronic governing system. This type of system is considered to be most reliable and accurate. The flyball head is driven by a synchronous motor that is supplied with current directly from a permanent magnet generator which is mounted on top of the unit and driven directly from the main shaft. As the unit starts to rotate, voltage is supplied immediately to the governor head motor locking in synchronism with the speed of the unit.

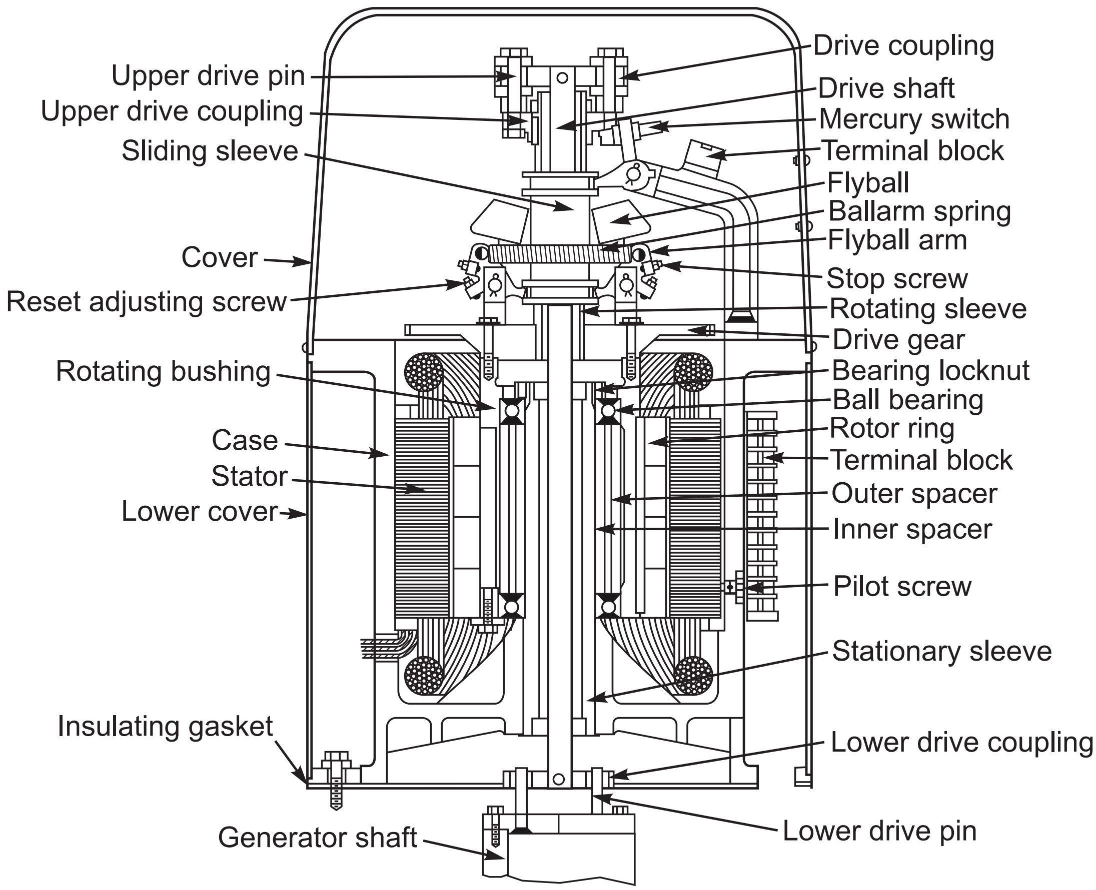

Fig. 14. Permanent magnet generator (Woodward Governor Co.)

In the event of failure of the governor drive, the governor senses the lower speed and the shutdown solenoid will shut the unit down when it is de- energized. When this occurs, the shutdown rod is raised and the hydraulic system that operates the wicket gates is actuated. The equipment is part of the apparatus contained in a modern Woodward Cabinet Actuator.

Load limit: Another mechanically operated device called the load limit is provided to block the movement of the pilot valve in the opening direction to limit the output.

Auxiliaries: Unattended automatic generating stations are usually provided with the following additional devices placed on the governor: (1) normal shutdown device, (2) emergency shutdown device, (3) starting device, (4) interlock with generator brakes when provided, (5) interlock with main circuit breaker, and (6) automatic synchronizing and speed-matching devices.

Generator windings: The windings of most of the older small air-cooled generators had Class A insulation. The insulation of the stator windings on most modern generators is Class B or better and designed to withstand the turbine runaway speed.

Since about 1970, the insulation on stator windings of large hydrogenerators has consisted mainly of mica bonded with a synthetic thermoset resin, the so- called “hard” insulation systems. While these have high thermal stability and high dielectric and mechanical strength, serious problems with coil looseness and slot discharge have developed in a number of installations, leading to rapid erosion of the groundwall insulation.

Prior to 1970 the groundwall insulation on a large stator coil consisted mainly of mica bonded by asphalt which is relatively soft, especially when warm. The asphalt insulation readily conforms to the irregularities in the slot and when wedged a good contact is made between the semiconducting paint on the coil and the core laminations. The ”hard” insulations do not fit so snugly in the slots and loosening of wedges and side packing and shrinkage or creep occurs when the machine is in operation. Magnetic forces at double rated frequency or about 10 million cycles a day will cause the loose coils to vibrate and pound. Wearing of the groundwall insulation results and failure will occur if the condition is not corrected.

Although significant differences exist between the thermoset systems from different manufacturers, they are all considerably harder than the asphalt insulations. The mica can be all mica splitting, all mica paper, or a combination of both. The thermosetting resin can be applied by vacuum pressure impregnation or by using resin-rich tapes. The resin can be either polyester or epoxy with heat distortion temperatures varying from 65°C (175°F) to 150°C (328°F).

Hydrogenerators that are constructed with thermoset stator windings require frequent thorough inspection of the windings, paying special attention to loose wedges, downward migration of slot filling material and wedge packing, coil separators, and bottom sticks. Deposits of white powder are an indication of “corona ash” or mechanical erosion of slot materials. In a number of cases stator windings with “hard” insulations have been replaced after only 5 years of service.

C.2 Generator Protection

Synchronous generators are employed in most hydroelectric generating stations. However, induction generators may be found where the generator is less than 2000 kVA and tied to a large-capacity system. For low-head applications, a speed increaser (gearbox) may be provided to take advantage of the higher-speed, lower-cost induction generator.

The modern synchronous generator may include a static exciter with its power transformer and voltage regulator. Brushless exciters mounted on the outboard end of the generator frame are also being used on new installations.

Larger generators (≥25 MVA) may be enclosed, air-cooled machines protected with automatic extinguishing systems actuated by heat detectors or by operation of differential relays.

Very large generators and reversible pump turbine units with motor-generators rated on the order of 540,000 hp (400,000 kW) sometimes have water-cooled rotor and stator windings. These are usually pressurized to about 85 psi (5.9 bar) and should be checked for leaks periodically.

Complete hydroelectric generating units are now available in package form in sizes up to about 6000 kW. These units are used for upgrading or enlarging existing low head hydroelectric sites or for use at new small dams. Surgecapacitors and surge arresters are also provided in a terminal box for the generator leads.

Figure 15 is a one-line diagram of a single unit synchronous hydroelectric generator illustrating the application of the protection recommended in Table1 for salient pole generators.

Figure 16 is a similar diagram illustrating the electrical protection recommended for induction generators.

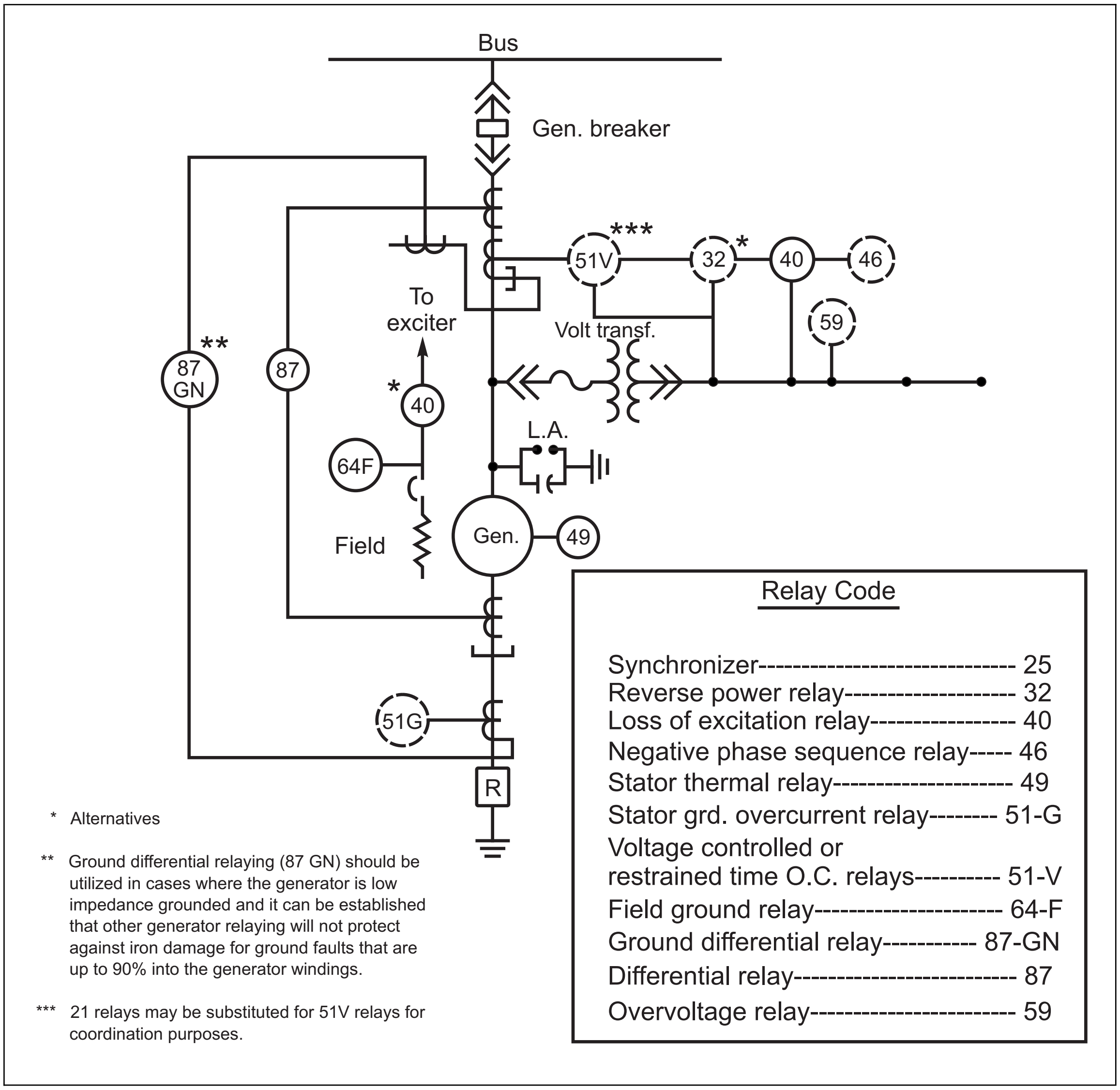

Fig. 15. Protective devices for synchronous hydroelectric generator. Note: Large machines should have all protective devices shown. Small machines (as defined) should have only those devices shown by dashed lines.

C.2.1 Generator Fire Detection Testing

Fire tests were conducted to determine the most effective fire detection for an open type vertical 65 MVA air-cooled generator (Dawson 1970). The tests were conducted by the Aluminum Company of Canada in 1969. One series of tests was conducted using a propane burner, another with an electrical fault as the ignition source. The objective of the tests was to determine whether a fire detection system could detect a fire with the machine in operation before damage occurred to four coils. The primary coil insulation was mica flake on paper backing. The end turn insulation was a varnished cloth.

In one series of tests a propane burner was used with flames projecting against the upper winding end turns. Air flow through the generator during normal operation prevented fire development. In another series of tests a turn-to-turn fault was simulated. A small fire developed in the region of the fault. The electrical protection remained in service. The generator went through a normal shutdown sequence with the machine stopping in about 3 minutes. Fire size increased rapidly. The temperature increase was detected by heat detectors two minutes after the machine stopped. Twelve minutes after stoppage, when the fire had reached dangerous proportions, the water spray system was activated and the machine was brought up to speed to extinguish the fire. It was noted that water was better distributed with the generator at rated speed. Damage was limited to about five coils. The top cover of the generator was warped.

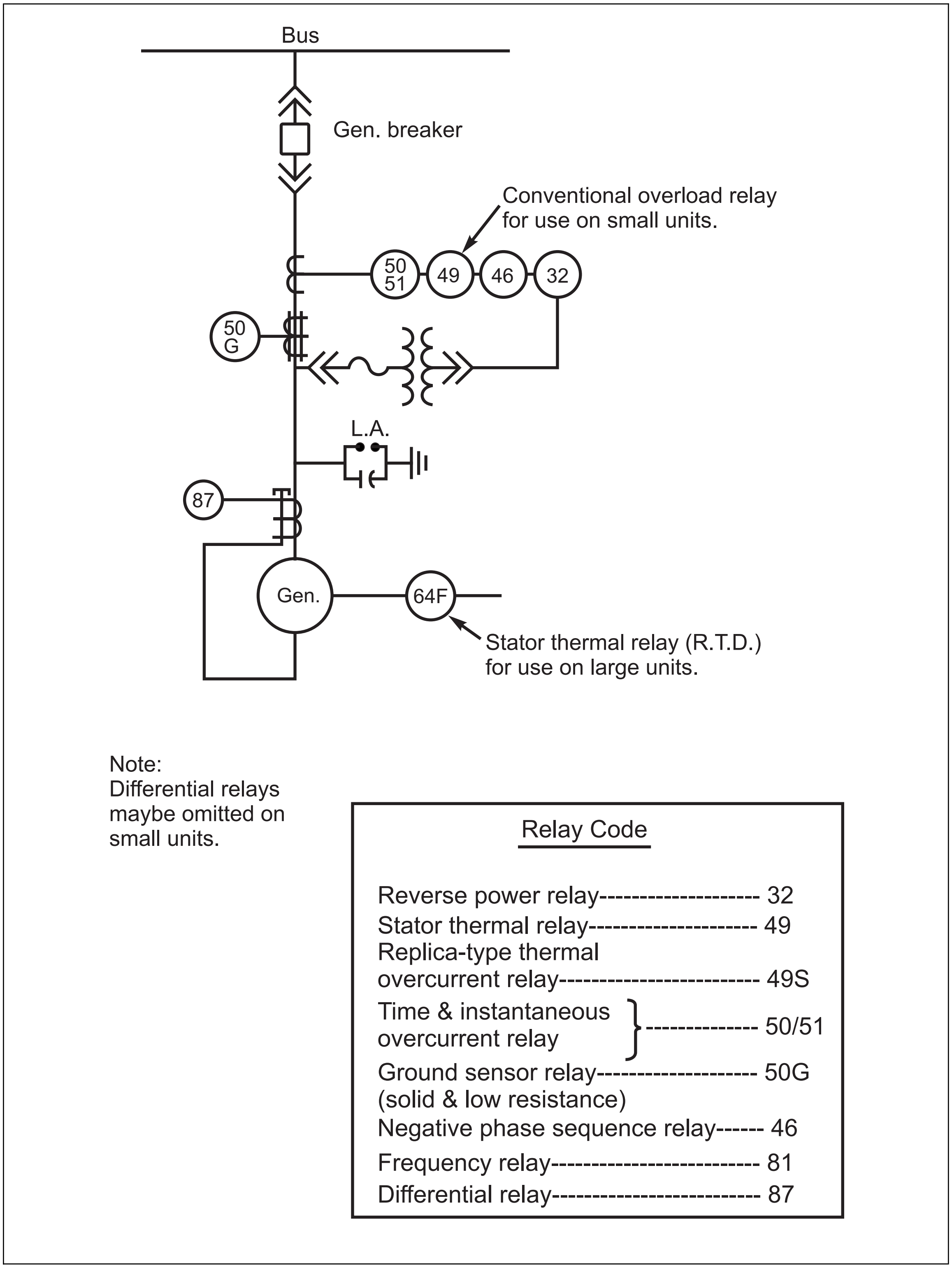

Fig. 16. Recommended protective devices for induction hydroelectric generators

Tests were conducted to compare the response time of smoke and heat detection. Smoke detectors were arranged so they were de-energized, until the generator came to a stop, after the occurrence of the fault. Six tests were conducted. Smoke detectors operated in all tests, most within 6 seconds after the generator stopped. Thermal detectors did not go into alarm during these incidents. It was concluded that smoke detection provided a significant chance of false alarm, making heat detection a more reliable method. Sincethese tests, there have been improvements in smoke detector technology. If smoke detectors are used there still are cases where smoke detection would need to be bypassed, such as when brakes are used to slow the generator (Dawson 1970).

C.2.2 Generator Fire Hazards

Fires occurring when the generator is in operation are caused by electrical faults although not all faults result in fire. Generator fires are low- frequency events, and fires involving generators with thermoset insulation are extremely rare.

Electrical protection should be capable of quickly isolating the generator following detection of a fault. Before the generator is isolated, electrical energy flows from the network to the fault. After circuit breaker trip the generator is isolated from the network and energy should be limited to that generated during wind down of the generator. Oil-less circuit breakers have a rated interrupting time of 5 cycles (IEEE 141-1993). Generators reportedly take from 2 to 5 minutes to wind down depending on the size of the machine.

Combustible loading in the generator could make a difference in the event of fire. The generator includes the following combustibles:

A. End turn insulation, including varnish tape, varnish on fiberglass tape, and mica on paper backing.

B. Winding insulation. Winding insulation may be thermoplastic or thermoset. Thermoplastic insulations developed in the early 1900s were asphalt resin and mica. Asphalt-mica insulations are not currently manufactured but a number of generators in service have this type of stator winding. Thermoset insulation was developed in the 1940s and 1950s. Most insulation is polyester or epoxy resin-impregnated mica tape. Use of thermoset insulations allows operation at higher temperatures with a higher power output.

C. End shields (may be fiberglass or metal).

D. Cable. The cable trays in the generator housing may be several feet (meters) long.

E. Transformers. Current or potential transformers (CTs, PTs) are usually dry-type and encapsulated. CTs, PTs, and cable occupy one or two 10 to 15 degree areas of the generator casing. They are used to diagnose problems, trip, and transmit power.

F. Contamination. Generator contamination may result from oil leakage and dust from insulation materials and incoming air. If a fault occurs in a generator with asphalt-mica insulations, a fire could be expected to continue to burn when power to the generator has been isolated. An automatic fire protection system is needed.

For polyester or epoxy insulations, loss experience indicates that in many cases a fire will self-extinguish if electrical protection promptly isolates power from the network. There has also been loss experience indicating that a high-energy fault may result in generator temperatures exceeding 300°F to 400°F (150°C to 205°C). Polyester and epoxy resins could be ignited by the fault and would continue to burn. Where a fire protection system is installed and operates properly, damage will be limited. Where a fire protection system is not installed there could be major damage to the generator.

If electrical protection does not isolate the generator, it is expected that there will be complete damage to the generator. Fire protection is typically interlocked with electrical protection and will not operate if electrical protection does not isolate the generator.

Original equipment manufacturers have proprietary insulation formulations. with varying fire properties. Standard fire tests do not duplicate the high- energy exposure that could exist following a fault in a generator (IEEE 141- 1993).