ELECTRIC AC GENERATORS

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1.0 SCOPE

This data sheet covers round rotor, alternating current (ac) generators of all sizes used in industrial and electric utility locations. Steam turbine, combustion turbine, hydraulic turbine, and internal combustion engine-driven generators are discussed within this data sheet. Hydraulic turbine generators with salient pole rotors are covered in Data Sheet 5-3/13-2, *Hydroelectric Power Plants*.

The focus of this data sheet is on synchronous machines, but most topics cover induction-type generators and synchronous condensers as well. Basic operation, protection, inspection, and maintenance of generators are described.

Refer to DS 5-20 and DS 5-23 for emergency generator loss prevention guidance. Refer to DS 7-79 and DS 7-101 for fire hazard loss prevention guidance for turbine generators.

1.1 Hazards

Electrical failure is the main hazard associated with electric ac 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 rupture of retaining rings, bearing damage, loss of lubrication, cooling fan blade fractures, and cracked rotor forgings.

Electrical and mechanical failures can destroy the generator and result in cascading effects, such lubrication oil fires, hydrogen gas explosions, and electrical system instability that could affect other generators.

1.2 Changes

January 2026. Interim revision. Minor editorial changes were made.

2.0 LOSS PREVENTION RECOMMENDATIONS

2.1 Fire Protection

2.1.1 Provide fire protection for lube oil systems, seal oil systems, hydraulic oil system, and hydrogen system in accordance with Data Sheet 7-101, *Fire Protection for Steam Turbines and Electric Generators*, and Data Sheet 7-79, *Fire Protection for Gas Turbines*. For synchronous condenser substations, provide fire protection in accordance with Data Sheet 7-79, *Fire Protection for Gas Turbines*.

2.1.2 Protect cables for generators in accordance with Data Sheet 5-31, *Cables and Bus Bars*.

2.2 Equipment and Processes

Generator equipment protection practice depends on application, generator size, criticality, and operating environment. There are many different and equally valid ways of achieving the same level of electrical protection.

2.2.1 See Table 1 for a list of recommended protective and alarm devices for generators of different sizes.

- Figure 1a shows a recommended electrical protection scheme for generators less than 10 MW.
- Figure 1b shows recommended electrical protection scheme for industrial generators rated at 10-50 MW.
- Figure 1c shows a recommended electrical protection scheme for utility generators rated at 50-100 MW.
- Figure 1d shows recommended electrical protection scheme for utility generators bigger than 100 MW.

Table 1. Recommended Protective and Alarm Devices for AC Generators

IEEE/ ANSI Device No.	*Protective Relay*	*Purpose*	*<10 MVA*	*10-50 (MVA)*	*50-100 (MVA)*	*>100 (MVA)*
21 or 51V	Distance protection relay or voltage controlled restrained time over current relay	Provides backup protection for system or generator zone phase faults	X	X	X	X
24	Volts per Hertz relay	Protects the generator from overexcitation		X	X	X
25	Synchronism check relay	Prevents generator circuit breaker from closing when the generator is not synchronized with the electrical grid or other generators			X	X
32	Reverse power relay[1]	Anti-motoring protection for the generator and the prime mover	X	X	X	X
40	Loss of field relay[2]	Protects the generator in the event of a loss of field		X	X	X
46	Negative sequence current relay	Protects the generator from unbalanced system faults or unbalanced load		X	X	X
49	RTD in stator winding	Detects overload	X	X	X	X
49	RTD in cooling system	Detects a failure of the cooling system	X	X	X	X
49	RTD in stator core	Detects increased temperature from core faults			X	X
51 TN	Time overcurrent relay	Backup protection for stator ground faults (provided on step-up transformer neutral)			X	X
59	Time delay overvoltage relay	Protect the generator stator winding from over voltage			X	X
59 GN, 51 GN	Stator ground fault ~90%	Primary stator ground fault protection with 90~95% winding coverage	X	X	X	X
27TN[2]	3rd harmonic-based relay to provide stator ground fault 100% with 59G	Primary stator ground fault protection for high resistance grounded generator to cover 100% winding coverage by using it in conjunction with conventional 59G stator ground fault protection			X	X
64S	Subharmonic injection relay	Alternative to 3rd harmonic-based relay 27TN for 100% stator ground fault protection			X	X
60	Voltage balance relay	Detects blown instrument transformer fuses, which render protection relays ineffective		X	X	X

Table 1. Recommended Protective and Alarm Devices for AC Generators (continued)

IEEE/ANSI Device No.	*Protective Relay*	*Purpose*	*<10 MVA*	*10-50 (MVA)*	*50-100 (MVA)*	*>100 (MVA)*
63	Transformer pressure[3]	Protects the generator in the event of a step-up transformer fault	X	X	X	X
64 F	Field ground fault relay[4]	Generator field winding ground fault protection			X	X
71	Transformer oil level relay[3]	Step-up transformer low oil level	X	X	X	X
78	Loss of synchronism relay	Trips the generator when it loses synchronism with the electrical system (out-of-step condition)				X
81	Frequency relay	Protects the generator from over-frequency or under frequency operation			X	X
87 GN (applicable for low resistance grounded unit)	Differential relay	Backup stator ground fault protection for low resistance grounded generator		X		
87 G	Differential relay	Protects the generator from faults within the generator zone	X	X	X	X
87 T	Differential relay[3]	Protects the generator from faults within the step-up transformer zone		X	X	X
87 U	Differential relay[3]	Protects the generator from faults within the overall generator and step-up zone			X	X
50/27	Inadvertent energizing	Protects the generator from accidental energization while it is on standstill			X	X
50BF	Breaker failure protection	Protects the prime mover and generator when generator circuit breaker fails to trip open during normal shut down or protective operation, by tripping the next upstream backup circuit breaker				X
	Bearing vibration sensor		X	X	X	X
	Liquid level detector (H2, water cooled, or air cooled with internal heat-exchangers)		X	X	X	X
	H2 dewpoint	H2 cooled machine & stator bar water cooled machines				
	H2 pressure sensor	H2 cooled machine & stator bar water cooled machines				
	H2 purity	H2 cooled machine & stator bar water cooled machines				
	Cooling water flow	Stator bar water cooled machines				
	H2 level in the cooled water system	Stator bar water cooled machines				

Note 1. Not applicable to synchronous condensers
Note 2. For generators with permanent magnet exciters, loss of field protection is not required because the field is always available from the permanent magnets.
Note 3. Applicable to unit-connected generators (via step-up transformers).
Note 4. Applicable to generators with slip rings.

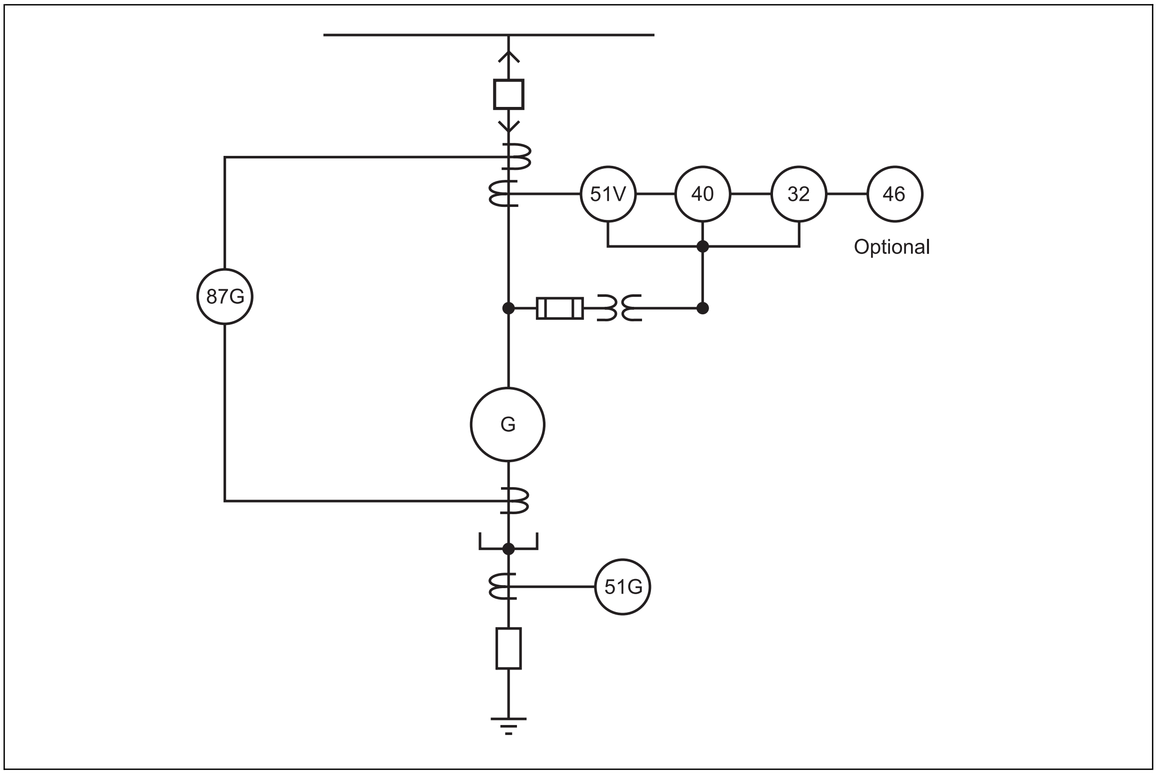

Fig. 1a. Recommended protection scheme for industrial generators less than 10 MVA with low resistance neutral grounding

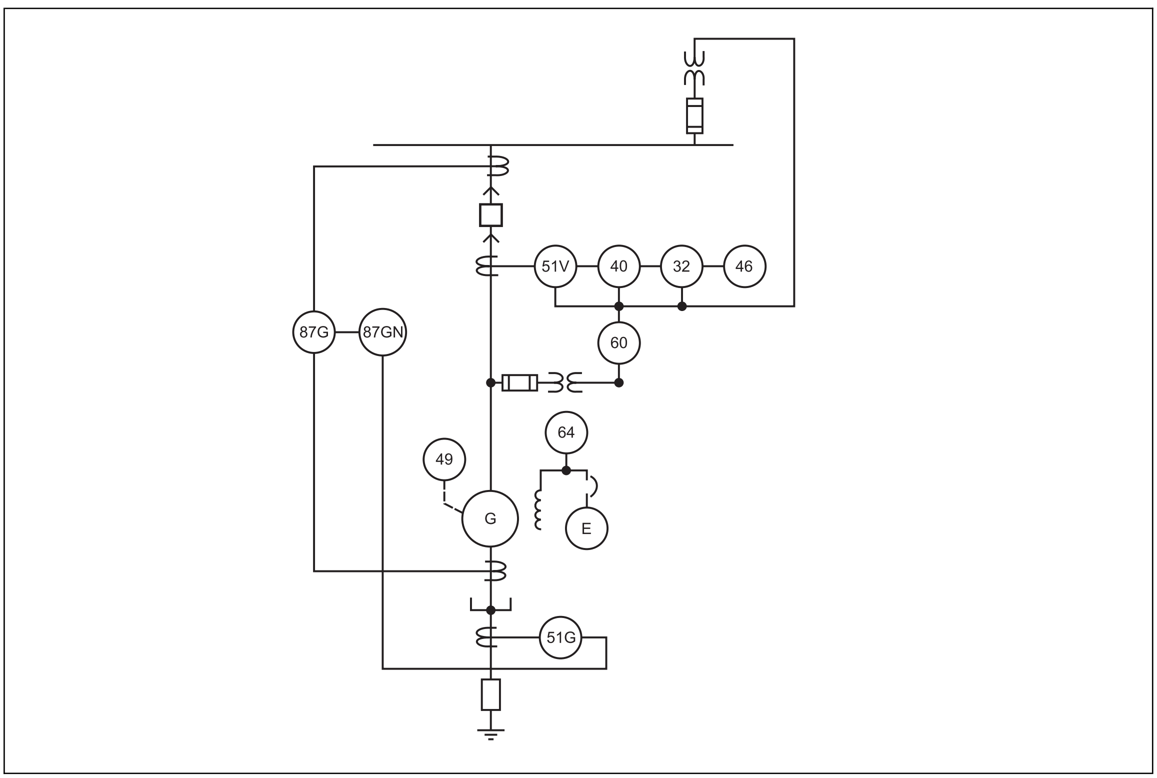

Fig. 1b. Recommended protection scheme for industrial generators less than 50 MVA but bigger than 10 MVA with low resistance neutral grounding

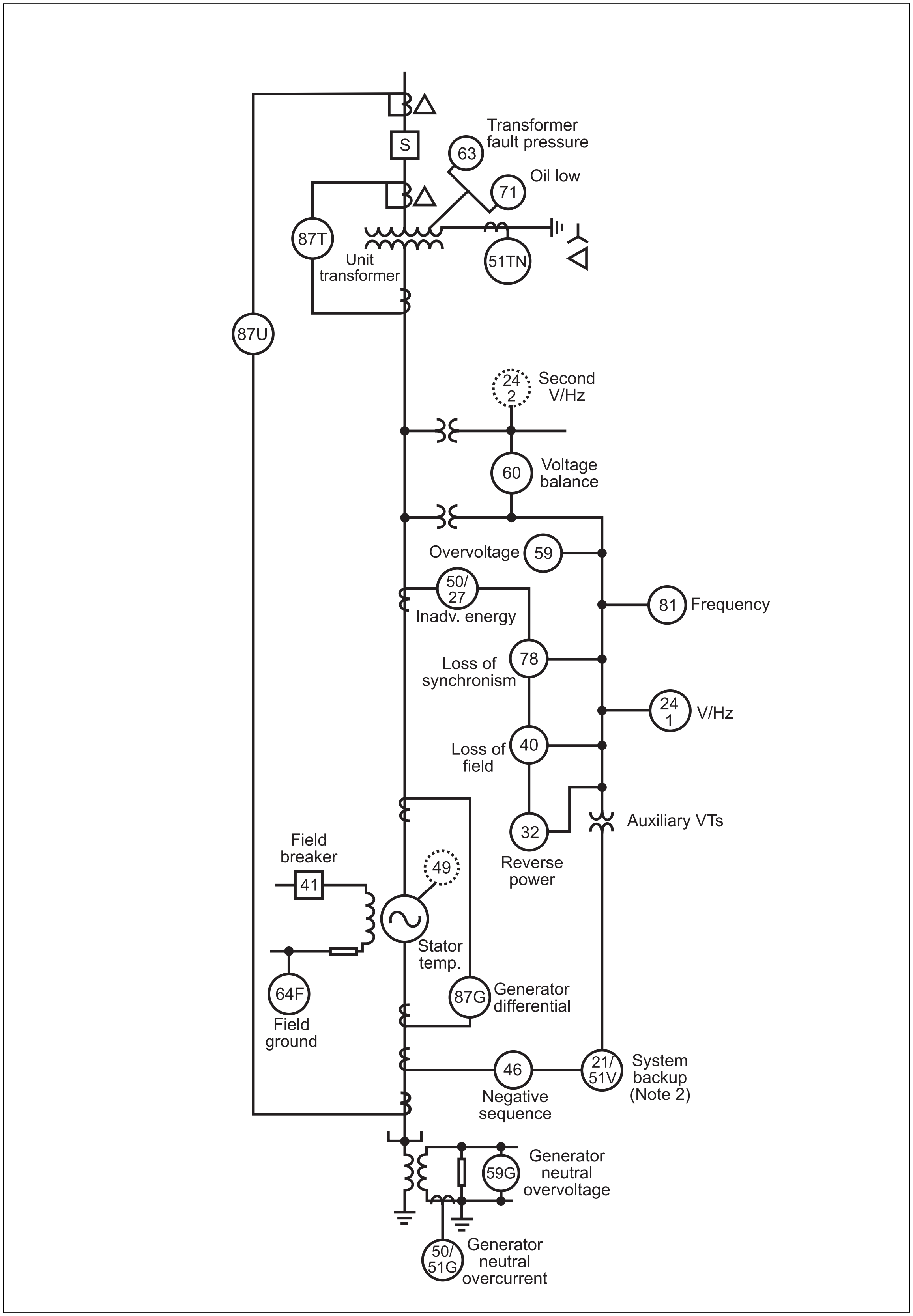

Fig. 1c. Recommended protection scheme for utility generators less than 100 MVA with high resistance neutral grounding resistance neutral grounding

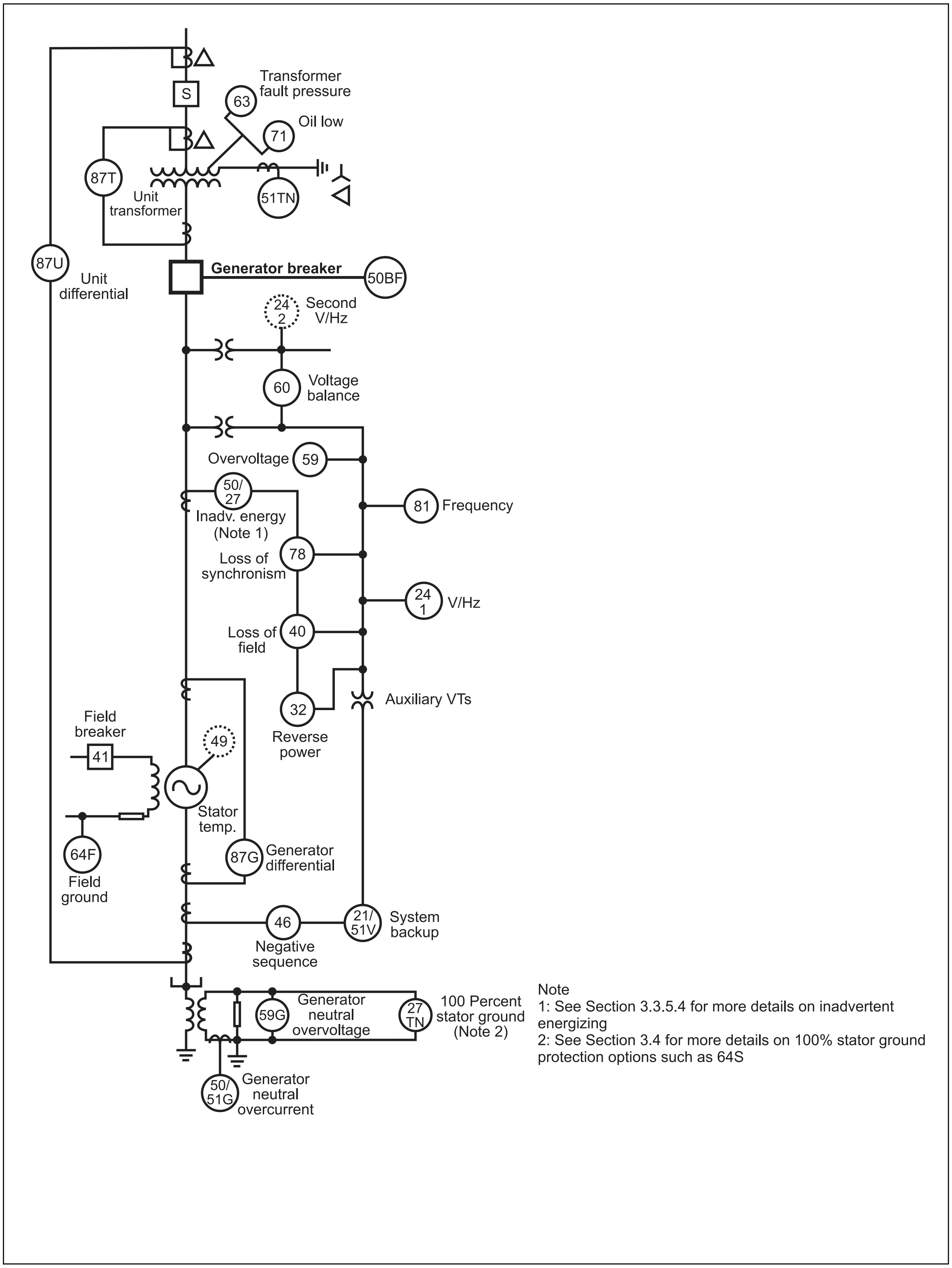

Fig. 1d. Recommended protection scheme for utility generators more than 100 MVA with high resistance neutral grounding resistance neutral grounding

2.2.2 Alternative schemes to those listed in Table 1 may also be acceptable, subject to review by protection relay engineers and qualified electrical engineers.

2.2.3 Have protective and alarm devices set based on engineering short circuit and relay coordination studies. It is inappropriate to use factory default settings. Have the studies conducted by engineers experienced with protective relaying.

2.2.3.1 Perform electrical short circuit and relay coordination studies when there are any changes, such as generator capacity upgrading, protection and system changes, or neutral grounding resistance scheme changes.

2.2.4 There are four common methods of tripping the generator in the event of an electrical fault or abnormal operating condition:

A. Simultaneous tripping. Trip the generator breaker, field breaker, and prime mover simultaneously. This method is used for internal generator faults or severe faults inside the generator zone, or excessive motoring events.

B. Generator tripping. Trip the generator breaker and field breaker but leave the prime mover online. This method is used for abnormal operating conditions external to the generator. It allows the generator to be returned to service quickly if the external abnormal conditions are corrected.

C. Unit separation. Trip the generator breaker but leave the field breaker closed. This is a full load rejection trip that leaves unit auxiliary loads connected to the generator. This method is used for power system disturbances, such as underfrequency or out-of-step conditions. It allows the generator to be returned to service quickly when the system is returned to normal operating conditions.

D. Sequential tripping. Trip the prime mover, then trip the generator breaker and field breaker on reverse power. This tripping method reduces the risk of an overspeed of the prime mover. This method is used as the normal shutdown mode, and for mechanical trips such as turbine-initiated trips. Sequential tripping automatic control logic relies on the indication of a turbine trip supervised by electrical reverse power relay to initiate the generator main breakers and transfer of unit auxiliary busses to a standby power source.

Table 2 summarizes the tripping philosophy for each protective and alarm device. This tripping philosophy may be modified based on the type of prime mover, the impact of sudden loss of generation, the need for a controlled shutdown of auxiliary loads, and operating experience.

Table 2. Generator Tripping And Alarming Philosophy

Device	*Tripping Mode*	*Open Generator Breaker*	*Open Field Breaker*	*Trip Prime Mover*	*Alarm*
21 or 51V	Unit separation trip[1]	×			
24	Simultaneous trip	×	×	×	
32	Simultaneous trip[2]	×	×	×	
40	Simultaneous trip	×	×	×	
46	Unit separation trip	×			
49	Alarm				×
50BF[3]	Trip break-up breaker				
51 GN	Simultaneous trip	×	×	×	
51 TN	Simultaneous trip	×	×	×	
59	Generator trip	×	×		
59 GN and any other stator ground fault relays	Simultaneous trip	×	×	×	
60	Alarm				×
63	Simultaneous	×	×	×	
64F	Generator trip	×	×		
71	Alarm				×
78	Unit Separation trip	×			
81	Unit Separation trip	×			
87 GN	Simultaneous trip	×	×	×	
87 G	Simultaneous trip	×	×	×	
87 T	Simultaneous trip	×	×	×	
87 U	Simultaneous trip	×	×	×	
Bearing vibration	Alarm (for <25MW unit) Alarm and sequential trip (>25MW unit)				
Liquid level detector	Alarm				
H2 dew point	Alarm				
H2 pressure	Alarm				
H2 purity	Alarm				
H2 leak in the cooling water	Alarm				
Cooling water flow	Alarm				

Note 1. Where 21/51V is used as backup protection. If used as primary protection, employ simultaneous trip method.
Note 2. Relay 32 is also used in the sequential trip sequence control logic.
Note 3. See further guidance on 2.2.5

2.2.5 Provide circuit breaker failure relays (50BF) with the following minimum features:

A. The initiation of breaker failure relays should not be inhibited by failure of breaker control mechanism. For example, the low-pressure lock-out of an SF6 gas-insulated generator circuit breaker should not inhibit the operation of the breaker failure relay.

B. The initiation mechanism of the breaker failure relay should not be bypassed for emergency manual unit shutdown.

C. The breaker failure relay should be initiated by both normal shutdown trips and protection operation.

D. Provide an alarm for breaker failure events and route the alarm to the power plant control room. This alarm should be a high priority and acknowledgeable. In addition, the operating procedure should address the scenario of breaker failure and any other type of motoring event. The maintenance program should, at minimum, include the following:

1. Testing the alarm function for low pressure if the circuit breaker is SF6 or pressured air insulated.
2. Testing the alarm function of low voltage of the DC circuit used for generator circuit breaker tripping mechanism.

Circuit breaker failure relays (50BF) are used to protect turbine-generator units from damage due to motoring events. More details can be seen in Section 3.3.5.3 and Section 3.3.5.8.

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

2.2.7 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.

2.2.8 Operators

2.2.8.1 Refer to Data Sheet 10-8, *Operators*, for guidance on developing operator programs. This includes operator training, standard and emergency operating procedures (SOPs and EOPs), the competence of operators in their day-to-day roles, the supporting management structure and the organizational culture.

2.2.8.2 Ensure operators are trained to identify abnormal operational events that may lead to equipment damage, such as generator motoring or loss of DC power. Ensure standard and emergency operating procedures are in place to identify, prevent or mitigate the effect of these conditions on the safety of operating the equipment. See Data Sheet 7-109, *Fuel Fired Thermal Electric Power Generation Facilities*, for more information on written procedures.

Most turbine-generator motoring events occur during shut down or routine system trip based on FM loss experience. If operators are well-trained and aware of when a motoring situation develops, they can make the correct decision to prevent or mitigate damage to the turbine-generator unit.

2.2.8.3 Create an emergency operating procedure for investigating the cause and origin when the protective device trips the machine or when the machine is not fit for continued service. These situations can include field ground fault, cooling water leak, significant vibration increase, high stator/rotor winding temperature, hydron low purity alarm, close-in fault at the GSUs or generator circuit breakers.Clearly document the actual steps following the isolation of the machine. Inform the manufacturer of the machine with suspected failure, especially when the machine is under warranty. Include the following items in the investigation procedure before restarting:

- Collect and review data such as operating condition, process alarms and trip sequence prior to and during the initial trip, records of maintenance work that may include reports on past problems, machine inspection and testing data.
- Perform an onsite equipment inspection for abnormal conditions such as water leaks or pouring, tripped breakers, noise, vibration and smells.
- If internal damage is suspected, perform an internal visual inspection and electrical testing evaluation. At a minimum, perform insulation resistance and polarization index testing.
- Based on the results of the investigation, implement appropriate loss prevention strategies for risk improvement before restart.

If the operator completes an initial investigation, and restarting results in the unit tripping a second time, elevate the issue to management and initiate a formal root cause analysis prior to restarting. Reference Data Sheet 10-8, Operators, and Data Sheet 7-43, *Process Safety*.

2.3 Operation and Maintenance

2.3.1 General

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

2.3.2 New Generators and In-Service Generators That Have Had Major Modifications or Repairs (Including Rewind)

2.3.2.1 Ensure the following tests are performed prior to commissioning or returning to service. Review the testing results if the tests are performed at the factory. Some of these tests may be performed before the unit arrives on site.

A. Stator (new generators or when major repairs/modifications involving the stator are made):

- Core loop test
- Wedge tightness test
- Slot semiconductive coating resistance testing
- Stator endwinding resonance testing (“bump test”)
- Winding DC resistance measurement
- Stator insulation resistance and polarization index testing
- Hi-pot test (more details in Section 2.3.9)
- Leak testing of inner water-cooled system whenever relevant

B. Rotor (new generators or when major repairs/modifications involving the rotor winding are made):

- Rotor winding resistance
- Voltage drops testing, Recurrent Surge Oscillation testing, or Impedance testing
- Rotor insulation resistance and polarization testing

If testing is conducted by the vendors, the owners or their representatives should witness the testing and/or review the results prior to commissioning or returning to service.

Note: For new generators, core loop testing, semiconductive coating resistance, and bump testing are usually conducted at the factory so any deficiencies detected can be corrected before shipping.

2.3.2.2 Perform a generator major or in-situ robotic inspection, and generator testing per Table 3 for major before the expiration of the generator warranty, typically within 1 to 3 years after commissioning, to detect any potential deficiencies introduced during the initial period of operation, installation, etc.

2.3.3 In-Service Generators

2.3.3.1 Operate the generator and its supporting systems in accordance with approved operating instructions and within the prescribed generator mechanical, thermal, and electrical limits (i.e., the capability curve). Refer to Data Sheet 10-8, *Operators*.

2.3.4 Condition Monitoring

2.3.4.1 Condition monitoring (includes online) is recommended for the following:

A. Generators where the loss of the unit will have significant business impact.

B. Generators that are on condition-based maintenance programs

2.3.4.2 Provide online condition-monitoring systems to monitor the following parameters:

- Rotor winding temperature detectors (continuous)
- Stator winding temperature detectors (continuous)
- Core temperature monitors or Core monitor (continuous)
- Air gap flux probes (periodic)
- Partial-discharge (PD) monitoring sensors or electromagnetic interference (EMI) on line testing (periodic). For air-cooled generators, ozone monitors can be alternative to partial-discharge detectors.
- Bearing vibration sensors (continuous)

- Stator end-winding vibration sensors (continuous)
- Shaft voltage and current sensors (continuous)

2.3.4.2.1 When flux probe and/or PD online condition monitoring are installed, perform annual reading for trending at minimum. Increase the frequency when abnormal increase of the reading is detected.

2.3.4.2.2 When shaft voltage and current monitoring system is installed, perform monthly reading. Increase the reading frequency to weekly when the readings start to increase.

2.3.4.2.3 Establish an effective online condition monitoring program as part of the inspection, testing, and maintenance program with at least the following elements:

A. Establish clear ownership of the online condition monitoring system and interpretation of data gathered from sensors. The data should be periodically reviewed and integrated with all available periodic offline testing, in-service testing, and operating history for condition assessment.

B. Establish generator specific criteria (including upper and/or lower absolute values as well as rate of changes/trending values) based on baseline value and trending for each parameter measured to identify results that will require further evaluation of generator conditions with corrective action taken where required.

C. Perform periodic calibration of the instrument & sensors per OEM guidance

D. Ensure personnel evaluating the monitored variable(s)have proper training and expertise.

E. Repair or replace any non-functional system or sensors at the next planned outage.

2.3.5 Generator Dismantle Inspection Intervals

Most turbine-generators undergo two types of dismantles: major and minor. A major dismantle usually involves the removal of the rotor from the generator or performing robotic inspection without removal of rotor for thorough visual inspection and off-line testing. During a minor dismantle, only the access covers are removed for limited visual inspection and off-line testing.

2.3.5.1 Establish and implement a foreign material exclusion (FME) program per Data Sheet 9-0 for all generator dismantle inspection activity.

2.3.5.2 Minor Inspection Intervals

Minor inspection intervals are normally driven by prime mover maintenance or inspections, such as gas turbine hot gas path inspection, where the prime mover is not disconnected from the generator. As a minimum, minor inspections should be performed (whichever the shortest):

- every 20k-40k EOH (interval EOH should be calculated using the prime mover OEM recommendations), or
- 500 starts, or
- 3~5 years.

2.3.5.3 Major Inspection Intervals

Major dismantle inspection of a generator is normally driven by prime mover major dismantle inspections where the prime mover is disconnected from the generator.

2.3.5.3.1 When the in-situ robotic inspection is adopted as alternative to rotor-out inspection, perform the following inspection and testing activities:

- Visual inspection by a robot
- Robotic stator wedge tightness assessment i.e., wedge mapping testing
- Robotic EL-CID test to detect damaged core insulation
- Visual borescope inspection by remote access camera
- Retaining ring NDE scanning

- Perform other electrical testing for major outage listed in Table 3
- Perform maintenance activities for auxiliary systems per Section 2.3.6.5

During the planning process, a rotor-out inspection contingency plan should be planned if robotic inspection returns poor results.

2.3.5.4 The following factors would justify generator dismantle intervals and scope that vary from the turbine dismantle intervals:

A. Significant changes or trends in the condition-monitoring data that indicate a developing problem with the generator

B. Advice from the OEM of problems that require frequent monitoring

C. A known problem that requires frequent monitoring

D. Operating experience and failure history that indicates the generator should be inspected more frequently.

E. Visual inspection and electrical testing results

F. Previous dismantle or inspection report finding

2.3.6 Generator Lay-Up

2.3.6.1 For generators that are shut down for standby (reserve shutdown) for a long period of time such as more than 2 weeks, implement a lay-up procedure to protect generators with at least the following steps:

A. Keep the whole generator compartment dry, such as by using dry nitrogen gas for preservation for H2 cooled machine or turning on built-in electric heaters for air cooled machine.

B. Lay up stator cooling system by completely draining water and dry the system.

C. Periodically turn the rotor to prevent rotor sagging.

D. Protect brush gear and collector ring surface from corrosion and dust accumulation.

2.3.7 Visual Inspection

2.3.7.1 Visual inspection is a highly effective method of detecting problems with the generator. Qualified persons should be employed to perform visual inspections at each dismantle and at all other opportunities.

Refer to Table 5 for common conditions to evaluate and their likely cause.

2.3.8 Testing

2.3.8.1 Table 3 lists electrical and mechanical tests typically performed at major and minor generator dismantles. Specific application of these test methods will depend on condition-monitoring data, visual inspections, operating experience, and failure history.

Table 3. Generator Testing

		≥20MW		<20MW	
Component	Test	Major	Minor	Major	Minor
Stator windings	Insulation Resistance	X[1]	X	X	X
	Polarization Index	X	X	X	X
	DC Conductivity	X	X		
	Capacitance	O[2]	O		
	Capacitance Tip-Up[3]	O	O		
	Power Factor	X	X	X	X
	Power Factor Tip-Up[3]	O	O		
	Partial Discharge	X	X		
	Wedge Tightness test	X		X	
	Stator End-Winding Resonance (bump test)	X			
	Capacitance Mapping (water-cooled stators)	X			
	Pressure and Vacuum Decay (water-cooled stators)	X			
Stator Core	Core Loop Test or EL-CID	X			
	Visual inspection for hot spots	X	X	X	X
Rotor windings	Insulation Resistance	X	X	X	X
	Polarization Index	X	X	X	X
	DC Conductivity Test	X	X		
	Open circuit [4]	X			
	Impedance[4]	X			
	Recurrent Surge Oscilloscope[4]	X			
	AC voltage drop test (i.e., pole balance voltage)[4]	x	x	X	X
Retaining Rings	NDE with rings removed [5]	O			
	Visual inspection for corrosion	X	X	X	X
	NDE of rings in-situ	X			
Rotor Fans	Visual inspection for cracking	X	X	X	X
	NDE of fan blades and vanes for cracking	O			
Rotor Forging	Visual inspection for cracking	X	X	X	X
	NDE of forging for cracks and inclusions	O			

Note 1. Recommended.
Note 2. Optional.
Note 3. Tip-up tests (either power factor or capacitance), off-line partial discharge tests, and online partial discharge monitoring are all used to assess PD activity within stator winding. Only one of them is needed for PD activity assessment.
Note 4. Rotor winding open circuit, impedance, surge comparison, recurrent surge oscilloscope, and ac voltage drop tests are all used to detect shorted turn in rotor winding. Only one of the tests is needed as a routine maintenance test.
Note 5. See Section 2.3.8.2 for more guidance.

Refer to Table 6 for a description of generator tests and the failure modes each test is capable of detecting. Acceptance criteria for each test are also provided in Table 6.

2.3.8.2 The most effective method of inspecting retaining rings for defects is by removing the rings from the rotor body. However, this can be a risky exercise and may result in damage to the rotor windings and the retaining ring. Remove retaining rings for inspection under the following circumstances:

A. Visual inspection indicates signs of corrosion on the external surfaces of the retaining ring.

B. Borescope inspection indicates signs of corrosion on the retaining ring shrink fit surface.

C. There have been incidences of moisture ingress in the generator.

D. In-situ ultrasonic inspection of the retaining ring shows crack-like indications in the body of the retaining ring.

E. Past inspections have found cracking of the retaining ring.

F. There have been incidences of significant negative sequence events or inadvertent energization.

G. There have been incidences of induction motoring.

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

2.3.8.4 Test generator circuit breakers, protection relays, batteries, and surge arrestors in accordance with Data Sheet 5-19, *Switchgear and Circuit Breakers*, at the major or the minor dismantle.

2.3.8.5 Also inspect and calibrate generator auxiliaries and their instruments during dismantles per OEM guidance, such as the lubrication oil system, hydrogen seal oil systems, air or hydrogen coolers, stator water cooling systems, terminal box, high-voltage bushings, excitation system, iso-phase bus ducts and hydrogen system, and stator resistance thermal detector (RTD).

2.3.9 Overvoltage (Hipot) Testing

2.3.9.1 Overvoltage testing is a potentially destructive test. For generators in-service, only conduct overvoltage testing after an evaluation has been performed based on online monitoring, electrical testing such as insulation resistance/polarization index testing, visual inspection, historical testing information, etc. This evaluation can help assess the risk of generator failure during the testing and help select a test voltage level to reduce the risk.

2.3.9.2 Carry out an overvoltage test 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.

2.3.9.3 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.

2.3.9.4 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 produces similar electric stress distributions.

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

2.3.9.5.1 An alternative is to increase the applied voltage in 1 kV steps, and measure the leakage current after 1 minute. This method is often referred to as step overvoltage testing.

2.3.9.6 The recommended maximum voltages for overvoltage testing are provided in Table 4.

Table 4. 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-phase voltage of the generator.

2.3.9.7 Do not perform any type of overvoltage test, including DC ramp/step overvoltage, on a generator close to the end of its life or with history of severe vibration/end-winding looseness. Consider refurbishment or stator rewinding of the generator.

The following are examples of insulation deficiency developed before the stator failed at DC overvoltage testing:

1. Fleet issue of end-winding resonance, where a sister unit on-site failed while in-service
2. Significant side ripple spring filler migration, per visual inspection
3. Significant loose wedges, per testing after greater than 50 years of service
4. Stator winding looseness with visual vibration indications at the end-winding assemblies/collector ring area and heavy greasing at the stator wedges

2.3.9.8 Surge comparison testing of the stator is also a potentially destructive test. A high voltage is applied to check the integrity of turn insulation. This test provides little diagnostic information. Failure of turn insulation will require the stator bar to be cut out and repaired.

2.4 Contingency Planning

2.4.1 Equipment Contingency Planning

2.4.1.1 When a generator 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 generator 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 generators:

A. OEM design information for the generator

B. Processes and procedures needed for removal, dismantling, transportation, availability, and installation of generator components

C. Review of any service contracts with OEM and/or vendors to identify the duration of delivery of generator components.

D. OEM and/or third party vendor review to determine the optimum spare part strategy.

2.5 Equipment Alerts

2.5.1 Original equipment manufacturers and alternative service providers issue technical bulletins or alerts when design or operating problems occur that differ from expectations. Establish a bulletin/alert management process to track, prioritize, and implement the bulletins/alerts utilizing a management of change process to address any impacts on programs, procedures and generator integrity and reliability. Urgency and implementation are designated by the timing and compliance codes within the bulletin/alert.

3.0 SUPPORT FOR RECOMMENDATIONS

3.1 Visual Indications

This section contains a table with a list of visual indications and their likely causes. It illustrates the value of visual inspection by a knowledgeable person. Visual inspection includes the use of borescopes, fiberscopes, robotic cameras, and other similar equipment.

Table 5. Visual Indications and Likely Causes

Component	*Visual Indication*	*Likely Cause*
Frame	Loose generator frame footing bolts	Foundation problems
	Cracked grouting around generator footings	Foundation 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	Oil or a dust-oil mixture in the stator bore	Hydrogen seal oil problems
	Carbon dust in air-cooled machines	Poor sealing between generator and exciter
	Red iron oxide powder in stator bore	Loose core
	Greasing or dust (forming a magnetic mixture of dust and oil)	Fretting of core laminations, 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	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
	Strong ozone smell in air-cooled machines	Slot partial discharge activity
	Hollow sound when stator wedges are taped	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
	Puffy insulation around water boxes, signs of corrosion and water stains	Crevice corrosion or leaking water connections in water-cooled stator bars
	Greasing, dust, movement or cracks at end winding blocking support area	End winding vibration or loose

Table 5. Visual Indications and Likely Causes (continued)

Component	*Visual Indication*	*Likely Cause*
Rotor	Copper dusting in vent holes	Shorted rotor turns
	Overall copper dusting on rotor body	Excessive turning gear operation or cyclic operation
	Copper dusting at rotor end windings	Deteriorated end winding blocking
	Arc damage or discoloration at the contact area between the retaining ring and wedges	Motoring, loss of field operations, or wedge contact with retaining ring
	Pitting of contact area between wedges and rotor slot	Operation at unbalanced load, system oscillations, and other abnormal conditions
	Blocked vent holes	Possible rotor thermal sensitivity
	Cracking of ends of rotor body flex slots	Operation under abnormal conditions (e.g. out of step)
	Discolored or distorted wedges	Operation under abnormal conditions (loss of field, motoring, under frequency)
	Oxidation and pitting of retaining ring external surfaces	Poor operating environment (high moistures or corrosive contaminants)
	Fretting marks on shrink fit areas of retaining ring	Excessive overheating during operation or mechanical movement due to severe load changes
	Rotor tooth top cracking	Poor design
	Rotor tooth cracks due to fretting	Excessive overheating during operation or mechanical movement due to severe load changes
Bearings	Imbedded foreign material in babbitt	Contamination of lubrication oil
	Pitting of bearing or shaft surfaces	Poor shaft grounding or faulty bearing insulation
Fan	Cracks at roots or welds of cooling fan	Fatigue
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 problems with field current or high machine vibration
	Discoloration of brush springs	Overheating of brushes or poor brush pressure

Note: Applicable to asphalt-mica insulation systems only.

3.1.1 Robotic inspection (RI)

There are three mainstream approaches to RI devices for large generators: crawler type robots, cable drive robots and telescope mast robots. Crawlers have some means of self-propulsion through the air gap, the most common “caterpillar” tracks. They are connected to the device hardware through cables that supply power and control and also feed camera and sensor outputs back to the hardware for processing.

Cable-driven devices are rare and require both ends of the generator have to be opened to install the device. A system of fastening of the cables on each end of the machine is required, and usually, the coil retaining ring or fan blades are used. The cables both guide and power the robot up and down the air gap, and this system can then also be used to rotate the robot tangentially inside of the air gap. The drive mechanism for moving the inspection device axially in the air gap is mounted on the faster outside of the core

Telescopic mast devices are typically used for smaller air gaps. The drive and rotational location mechanism are usually mounted on the coil retaining ring. A telescopic arm or mast with the sensing equipment is attached to the end of the mast/tape.

Tables 6 and 7 are the characteristics comparison of various RI devices commercially available and under development. Figure 2 show some examples of deficiency picked by robotic inspection.

Table 6. Commercially RI Device Properties (With Permission From EPRI)

RI device	*Type*	*Minimum Gap Size*	*Disassembly required (one or both generator ends*	*Robotic EL-CID*	*Robotic Wedge Tapper*	*Experience*
GE Magic	Crawler	28.6 mm (1.126”)	One	Yes	Yes	>2600 inspections
GE Magic Junior	Telescopic	12.7 mm (0.5”)	One	Yes	Yes	
Alstom Diris Top	Cable car	25mm (0.984”)	Both	Yes	Yes	N/A
Alstom Diris small	Telescopic	12 mm (0.472”)	One	Yes	Yes	N/A
Iris RIV	Crawler	30 mm (1.181”)	One	Yes	Yes	N/A
Dekra/Brush Argis	Crawler	17 mm (0.669”)	One	Yes	Yes	N/A
Siemens FastGen	Crawler	22 mm (0.866”)	One	Yes	Yes	>2000 inspections

Table 7. New and Developing RI Device Properties (With Permission From EPRI)

RI device	*Type*	*Minimum Gap Size*	*Designed for specific OEM machines*	*Robotic EL-CID*	*Robotic Wedge Tapper*	*Special or new features*
Mitsubishi	Crawler	Est. >20 mm (0.787”)	Mitsubishi mid to large gens	Yes	Yes	Proprietary wedge tapper
Toshiba	Crawler	Est. >31 mm (1.22”)	Toshiba mid to large gens >200MVA	Yes	Yes	Inspect machine with battles, UT test of rotor wedges/teeth
GE SAVANT	Telescopic	Est. >12 mm (0.472”)	GE gens smaller than 7FH2 (<300MW)	Yes	Yes	Neural networks, use rotor for low core flux test excitation “turn”
GE GENI	Crawler	Est. >21 mm (0.827”)	GE gens larger than 7FH2 (<300MW)	Yes	Yes	Image stitching, use rotor for low excitation “turn”. WITS wedge test, 7 HD cameras
ABB	Crawler	10 mm (0.394”)	ABB synch motor/gens	No	No	5 HD cameras
Ansaldo	Crawler	40 mm (1.57”)	Ansaldo	Yes	Yes	Device for inspecting down stator vent ducts

Fig. 2. Examples of footage taken during robotic inspection (Photo by courtesy of 3angles, Inc. and Iris Power)

3.2 Generator Tests

This section contains a table with a list of generator tests, the failure mode each test is capable of detecting, and the acceptance criteria for each test.

Table 8. Generator Tests

Test	*Test method*	*Tested Component*	*Detected Failure Mode*	*Acceptance Criteria*
Insulation Resistance	Apply dc voltage for 1 minute and measure leakage current.	Stator and rotor windings	Contamination, defects, and deterioration of ground insulation (i.e., slot insulation for rotor windings or ground wall insulation for stator windings	For pre-1970 vintage machines, minimum resistance should be about (E+1) Mohm. 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 Mohm.
Polarization Index	Ratio of the 10-minute insulation resistance	Stator and rotor windings	Contamination, defects, water ingress, and deterioration of ground insulation	A polarization index equal to or greater than 2 is an indication that the insulation is clean and dry. When the insulation reading at 1 minute is above 5000 Mohm, the calculated P.I can be disregarded If the field windings are not fully encapsulated in insulation, which is the case for majority of large generators, P.I value is not applicable.
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 another (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 difference between the two power factors.	Stator windings	Partial discharge activity due to ground wall insulation deterioration from thermal degradation or load cycling	Epoxy-mica, maximum tip-up of 1%; Asphalt-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 other two phases grounded).	Stator windings	Ground wall insulation deterioration due to thermal degradation or water ingress	Epoxy-mica: Typical power factor value is less than 0.5%.Asphaltic-mica: Typical power factor value is less than 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 8. Generator Tests (continued)

Test	*Test method*	*Tested Component*	*Detected Failure Mode*	*Acceptance Criteria*
Power Factor Tip-up	Measure the power factor 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 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 activities 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.
Wedge Tap	Tap each end of each wedge with a hammer and either listen to the sound 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 to global 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 of the slot should be loose. Two or more adjacent wedges in the same slot should not be loose. No wedges should be cracked.
Stator End-Winding Resonance	Tap the end windings with a hammer and utilize accelerometers to measure the vibration in the coil. Also listen to the sound of the winding after it has been bit. 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	No resonant frequency peaks between +10% and -5% of twice power frequency (i.e., 115-~135 Hz exclusion zone for 60 Hz machines, and 95-~115 Hz for 50 Hz machines)
Capacitance Mapping	Ground the stator winding and place a small metal plate over the end windings. Measure the capacitance between the metal plate and the stator bar.	Direct water-cooled stator bars	Water leaks resulting in contamination of ground wall insulation	Compare the capacitance measured between the metal plate and each stator bar. In general, nearly all of the data should fall between -2 and +2 times standard deviations from the mean. If the capacitance of a bar is greater than +3 times standard deviations above the average, this indicates that water is likely to have been absorbed by the insulation.

Table 8. Generator Tests (continued)

Test	*Test method*	*Tested Component*	*Detected Failure Mode*	*Acceptance Criteria*
Pressure and Vacuum Decay	Dry the stator cooling channels completely and draw a vacuum of about 0.2 Pa. Measure the decay in vacuum over 1 to 2 hours. This test does not require access to the stator.	After vacuum decay testing, to ensure dry stator cooling channels, pressurize with very dry air or nitrogen to 300 kPa and measure the pressure drop over 24 hours.	Entire water-cooled stator hydraulic system	Pinholes and cracks in hollow stator bar conductorsAny decay in vacuum greater than 1 ft^3 per day within 1 hour indicates the presence of a leak. A 10 kPa drop in pressure in 24 hours indicates the presence of a leak.Tracer gas (9SF6 or He) can be used to locate the leaks and a capacitance map performed to determine the effect of the leaks on the insulation.
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. Shorted rotor windings will result in lower generator output voltage for the same field current.
Recurrent Surge Oscillograph	Use a reflectometer to apply 100 V, high-frequency voltage pulses at both ends of the rotor winding and measure the voltage at the injection point as a function of time using an oscilloscope.	Rotor windings	Shorted turns, ground faults, and high resistance connections in the rotor winding	Compare the waveform from both ends of the winding. Differences in the waveform indicate the presence of a defect in the rotor winding. The location of the defect can also be determined from the shape of the waveform.
Loop Test	Excite the core to produce at least 65% but not more than 100% rated core flux and allow the core to soak for more than 1 hour to ensure the excited core without cooling does not undergo thermal runaway.	Stator core	Shorted or damaged core laminations	Hot spots with a temperature difference of between 5°C and 10°C indicate core defects.

3.3 Failure Modes and Abnormal Operating Conditions

This section briefly describes the common major hazards to ac generators in industrial facilities and utility generating stations.

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. Core lamination insulation damage can be caused by overheating, over excitation incidents, under-excitation, faulty core through bolt insulation, loss of field, foreign object damage or careless removal of rotors.

3.3.2 Stator Winding Failure Modes

Stator winding failures occur when either the groundwall or turn insulation fails and allows a short circuit to occur. Failure of ground-wall and turn insulation can occur due to the following causes.

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.

Thermal deterioration can occur mainly due to the following:

- Overloading of the generator
- Poor design or poor manufacturing
- Cooling system failure
- Overexcited and underexcited operation of the generator
- Negative sequence currents caused by phase imbalance
- High harmonics in the electrical system

3.3.2.2 Excessive Partial Discharge

Partial discharge (PD) is present in many high-voltage machine stator windings rated 4 kV and above. The main sources of PD in high voltage stator windings are (1) voids in the groundwall insulation; (2) slot discharge occurring between the bar surface and the core iron, and (3) discharges in the end winding portion of the stator. PD can be viewed as an erosive mechanism or a symptom of other electrical, thermal, or mechanical problems.

When excessive partial discharge activity is detected, it is very important to determine its type because each type of discharge has its own rate of deterioration and not all PD have the same significance.

3.3.2.3 Excessive 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.

There are mainly two forms of failure due to load cycling, depending on the type of insulation used.

A. Girth cracking: In the 1930s to the 1950s asphalt-mica insulation systems were used. Asphalt-mica is a thermoplastic and tends to expand and lock the stator bar into the slot. This creates a large axial tensile stress when the copper bar expands faster against the ground wall insulation and can cause cracking of the insulation around the girth of the stator bar. With repetitive load cycles, the cracking will increase until less and less insulation is left in the crack. A neck of reduced insulation forms in the stator bar which could extend all the way down to bare copper.

B. Tape separation: Modern insulation systems are epoxy-mica type and are not susceptible to girth cracking. These are rigid thermosets and can slide more freely within the slot so axial tensile stress due to differences in thermal expansion is reduced. Modern stator bars also have stronger armor tapes that are resistant to girth cracking. However, copper expands faster than groundwall insulation and this 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.

In addition to the above, excessive load cycling can act as a contributing factor to speed up the mechanical related degradation mechanisms in stator windings such as loose side filler and end winding vibrations.

3.3.2.4 Loose Stator Bars

This occurs only with stator bars using thermoset insulation in machines not manufactured using the global VPI (vacuum pressure impregnated) method. Thermoplastic insulation is used in older machines. It will expand into the slot to keep the stator bar tight within the slot. Thermoset insulation is rigid and so more susceptible to this problem

Stator bars are subject to high magnetically induced mechanical forces at twice the power frequency. Loose stator can cause the abrasion of the insulation by the rough surface of the slot. When the semiconductive coating on the surface of the insulation system is abraded away, then the insulation surface is not grounded well thus resulting in slot discharge. These partial discharges accelerate the deterioration of the insulation. Also, due to abrasion of insulation, the stator bars can become looser. So this failure mode is one of the fastest deterioration mechanisms.

Loose stator bars can be caused by the following:

A. Loose stator wedge.

B. Shrinkage of the insulation. After long operation, insulation materials tend to shrink as they thermally age. Also, in the first few years of operation, relatively significant shrinkage can occur as the groundwall insulation completes the curing process during operation.

C. Deterioration of supports in the slot such as ripple springs losing their elasticity in the presence of oil.

D. Loose wedges over time due to shrinkage, oil contamination or stator core movement.

E. Manufacturing defects.

3.3.2.5 Faulty Semi-Conductive Coating

Stator bars in machines rated 4 kV and greater are usually coated with paint or tape that utilizes 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 insulation failure occurs.

3.3.2.6 Vibration Sparking or Spark Erosion

Vibration sparking or spark erosion is an old failure mode which has become a problem with modern air-cooled generators, particularly large, air-cooled generators. It occurs at a generators with loose stator bar inside the slot in combination with low surface resistivity of the bar’s semi conductive coating. During normal operation of a generator, a current loop will develop along the bar axially, radially through the core lamination, axially along the key bars at the back of the bar due to the electrical magnetic induction in the loop. If a bar is allowed to vibrate, the current in this loop will be interrupted at a contact point to the core. The interruption of this current will form an arc to the core. If the semi conductive coating of a stator bar is too low, this current will be of significant magnitude and the resulting arc can damage the ground wall insulation by an erosion process. This phenomenon can happen at any bar regardless of the voltage level since it is primarily dependent upon the looseness and surface resistivity of the semi-conductive coating. Vibration sparking damage very fast acting. Experience has shown that vibration sparking in generators will lead to a stator ground fault failure in as little as 4 years.

Vibration sparking is primarily detected by borescope inspection. For air cooled units, a borescope can be inserted in the vent duct at the back of the core and the coil visually inspected on the side of the coil. In addition, an EMI signature can also be used to detect this phenomenon. Some studies indicate that a high capacitance PD sensor at the neutral point, which can see all 3 phases from the neutral side, and permits reliable identification of vibration sparking signals if the phenomenon is present close to the neutral point.

For the generators with vibration sparking issue, the only reliable solution is to rewind or replace the stator windings. The new stator windings should have the following features:

- Nonconductive top ripple springs
- Semi conductive side ripple springs
- Corona protective coating with adequate surface resistance to prevent spark erosion

3.3.2.6 Contamination

The surface of the stator winding can be contaminated with dirt, insects or plant by-products, especially in open cooling air units. The contaminant can also be moisture or oil. Oil comes from the bearings or the seal oil systems, whereas moisture comes from the environment, steam leaks, leaking cooling water systems, and/or from the seal oil system in hydrogen cooled machines. The contamination can affect the life of a stator winding in several ways such as electrical tracking , overheating or even cause loose stator winding.

3.3.2.7 End Winding Vibration

Stator windings vibrate due to magnetic forces during operation of the generator. The ends of stator windings hang outside the core ends and need to be properly supported. If the end windings are not adequately supported, excessive winding vibrations will occur leading to copper strand cracks, ground insulation abrasion, wedge looseness, etc. vibration spark and eventually result in a phase to phase or phase to ground short.

Excessive end winding vibrations are due to the following:

A. Poor design or installation of end winding bracing that lead to end-winding resonance excited by electromagnetic force frequency during the operation

B. Oil contamination (e.g., seal oil problems) causing end winding bracing to slacken and blocks to slip

C. An electrical fault (e.g., out-of-phase synchronization) that generates enough force to break end winding supports

D. Thermal aging of end winding insulation causing the insulation to shrink, with a resulting loss of bracing effectiveness

3.3.2.8 Cooling Water Leaks

Direct water-cooled stator bars circulate water through channels in the stator bar. Water leaks will result in electrical tracking or even flashovers if a large quantity of water is allowed to escape. Small leaks will be absorbed by the insulation and will reduce both its dielectric as well as its mechanical strength.

Water leaks are due to the following:

A. Poor workmanship, particularly where hoses are incorrectly attached to the nozzles at the end of the stator bar.

B. Crevice corrosion of the brazed joint of the water box or clip. The water box is located at the end of the bar, before the nozzle. Poor workmanship during brazing of the water box to the end of the bar can cause small pockets and gaps to be present in the brazed joint. Water is allowed to stagnate in the pockets and gaps, where it combines with the phosphor in the braze to form phosphoric acid. The acid corrodes the braze until tiny cracks develop in the brazed joint. Even with a higher hydrogen pressure, water will still leak out of these cracks by osmosis.

3.3.3 Rotor

3.3.3.1 Rotor Winding Turn-to-Turn Short

Rotor bar insulation consists of two components. Slot insulation, which provides the main insulation between the rotor bar and the grounded rotor forging, and turn insulation which provides insulation between individual turns in each rotor bar.

Shorted turns in a rotor winding result from failure of the turn insulation due to metallic contamination thus forming a conductive bridge between turns, winding distortion allowing adjacent turn to turn contact, or insulation abrasion caused by relative motion of the turns.

When shorted turns occur, localized overheating at the location of shorted turns due to circulating currents will develop leading to thermal sensitive vibration and further damage to adjacent component such insulation and/or retaining ring depending on the number, severity and location of shorted turns. A rotor can operate without incident for years with minor shorted turns. However damage can propagate and worsen causing more turns to be affected, or the slot insulation may become damaged causing a rotor winding ground fault event.

3.3.3.2 Excessive Load Cycling

The aging process of any generator can be split into two categories: operating hours aging and cycling aging. The aging mechanisms in each category are fundamentally different. The overall aging of a generator in an application will be a combination of the two categories and will depend on cycles and other operating conditions.

Cycling aging is mainly influenced by the design, and driven by frequency of cycling, operating experience, and maintenance practices. Many generators in service today are not designed for frequent cycling such as weekly or daily cycling. These operations have caused excessive low cycle mechanical fatigue such as cracking on generator components, particularly rotor components. FM recent loss experience has demonstrated that cycling operations can be directly linked to several failure mechanisms of the rotor, such as rotor winding movement, J-strap cracking, slot liner insulation cracking, and pole-to-pole crossover cracking.

Fig. 3. Examples of generator rotor related losses due to excessive load cycling

3.3.3.3 Rotor Winding Distortion

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.

Excessive load cycling will aggravate this failure mode.

3.3.3.4 Copper Dust

This failure mode is specific to rotor bars where each turn is made up of two uninsulated conductors (strands) placed next to one another. These strands are stacked radially in the rotor slot.

At normal operating speeds, centrifugal force prevents movement between the strands in a rotor bar. However, when the rotor is on turning gear and being rotated at slow speed, the strands are allowed to continually separate and pound against each another as the rotor is turned. This results in fretting of the copper strands and copper dust is produced. If sufficient copper dust is generated and distributed through the rotor, this could lead to ground faults or turn-to-turn faults.

3.3.3.5 Retaining Ring Damage

Retaining rings made of 18Mn-5Cr and 18Mn-4Cr steel are susceptible to water induced, stress corrosion cracking. Many owners have chosen to replace these retaining rings with rings made of 18Mn-18Cr steel because of the severe consequences of a retaining ring fracture. Other owners have chosen to leave 18Mn-5Cr and 18Mn-4Cr rings in service with rigorous controls to keep moisture away from the retaining rings and routine NDE of the retaining rings to check for cracking.

The 18Mn-18Cr retaining rings have a high immunity to water induced stress corrosion cracking. However, there have been a few reports of stress corrosion cracking of 18Mn-18Cr retaining rings in the presence of halides, chlorides, and copper ions.

Water-cooled stators are used in some large generators. These cooling systems present a significant water leakage hazard, particularly at hydraulic fittings between the cooling water hoses and the stator cooling headers. If a leak occurs, it poses a hazard not only to the windings, but also to the retaining rings. It might be impossible to dry the rings before corrosive attack occurs, but at the very least, when retaining rings have been exposed to moisture, the rings have to be removed and examined for evidence of pitting. If pitting is found, and it is of such a depth that it cannot be blended out within the manufacturer's limits, the ring will have to be replaced.

Retaining rings are highly stressed during operation as well as when the machine is idle. The best approach to preventing stress corrosion cracking is to keep moisture away from the rings during operation; idle periods as well as during outages. This can be done by frequent examination and leak testing of all hydraulic fittings. Care must also be taken to eliminate moisture during outages by heating and/or dehumidification of the rotor.

In addition to stress corrosion cracking, all retaining rings are subject to other failure modes such as arc pitting, overheating, mechanical fretting, and fatigue. It is important to regularly inspect retaining rings by visual and non-destructive evaluation.

The tight fit between the rotor and the retaining ring tends to loosen at operating speed. There have been instances where the fit was completely lost and the retaining ring left the rotor, causing extensive damage. It is advisable during dismantles to closely inspect the interfaces between retaining rings and rotors to detect any evidence of relative movement. If such movement is found, the retaining ring must be removed, and the interface built up by flame plating to restore the proper interference.

Care also must be taken to avoid excessive temperature during assembly and removal of a retaining ring. Some manufacturers have established a temperature limit of 660°F (350°C) to avoid reducing the fracture toughness of the retaining ring material, as well as its resistance to stress corrosion.

3.3.3.6 Fan Fractures

Fracture of cooling fan blades, support rings, spacers, and clamping rings is a serious mechanical hazard. There have been some cases of support or clamping rings or spacers breaking loose and flying into the stator end windings. The damage to the end windings can be considerable.

Fan blade fractures are usually the result of fatigue caused by resonant vibration. This is similar to failures of steam turbine blades in high-frequency fatigue and it implies a design error in establishing the natural frequencies of the fan blades. Therefore, it is to be expected that if a fan blade were to fail at all, it would fail early in its life, within the warranty period, particularly if it is integral with its support ring. However, in some instances fan blade fractures occur after many years of service. There are two explanations for this:

A. The aerodynamic excitation (circumferential flow-distortion in the air- or gas-cooling passages) has increased. This can only be caused by mechanical distortion of the passages that direct the air or gas flow into or out of the fan. Any distortion or blockage of this nature can be detected during partial dismantle inspections. It must be treated as an important maintenance item and corrected.

B. Deterioration of the fan blades or of their attachments, such that their natural frequencies have changed and critical resonance arises. In the case of some fans, the blades are attached to the support rings by mechanical fasteners. These might become loose, or the blades might be damaged in some fashion that would alter their natural frequencies. Such deterioration and damage also can be found during partial dismantle inspections. They must be corrected, and NDE performed where applicable, when found.

3.3.3.7 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 the bearing 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.

3.3.4 Abnormal Operation Conditions

3.3.4.1 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:

- Loss of field-to-main exciter
- Accidental tripping of field breaker
- Short circuits in field circuits, or in exciter armature
- Poor brush contact in exciter
- Reduced frequency because of exciter control problems
- Regulator failure
- 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.

3.3.4.2 Synchronization Errors

When a generator is tied into a utility bus, it must, 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.

3.3.4.3 Motoring

The following are various conditions for generator motoring:

A. Synchronous motoring. The energy to the prime mover is cut off, as in unit shut down, and the generator breaker does not open. The generator stays on line with the field energized and all generator auxiliaries in operation and begins operating as a synchronous motor. The generator can operate indefinitely as a synchronous motor drawing current from the System and spinning at rated speed. The concern here is for over heating the turbine rotating element expansion leading to turbine blade rubbing and excessive vibration, since there is insufficient steam flow to carry away heat produced by windage losses.

B. Induction motoring. If energy to the prime mover is cut off, as in a unit shut down, and the generator breaker does not open and the generator field is de-energized, the generator stays on line and begins operating as an induction motor with current flowing on the rotor forging. The speed will usually decrease slightly. Damage to the generator rotor depends on the length of time the generator is induction motoring. For a short time, a few minutes, there may be no damage. For a longer time, tens of minutes, serious damage and possible destruction may occur. The concern here is for both the generator and turbine rotating element expansion leading to turbine blade rubbing and excessive vibration as well.

C. Single-phase motoring. Single-phase operation, where one of the phases of the generator breaker does not open, (or does not close during synchronizing) greatly complicates any of the three motoring conditions mentioned above. The concern here is for the generator and turbine rotating element expansion leading to turbine blade rubbing and excessive vibration

A reverse-power relay together with breaker failure relays will protect turbine generator unit against motoring damage. A reverse power relay typically set to trip the generator breaker after sensing motoring for 30 seconds.

In addition, FM experience has demonstrated that most motoring events occur during unit shut down or restart with certain degree of human error. Well educated operations with sufficient knowledge of the system and unit condition when motoring situation develops can help significantly mitigate the consequence of motoring damage.

3.3.4.4 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.

The generator is connected to the system via a main transformer through a disconnect switch to a breaker and a half or ring bus configuration. A disconnect switch is used to isolate the generator, and then all the high voltage breakers can be put back in service.

The problem arises when the high voltage breakers are being closed to re-make the bus, and the isolation switch is inadvertently left closed, energizing the off-line generator. Often time generator auxiliaries are not in service when this occurs. The consequence is high currents induced in the rotor, which can lead to significant damage in a matter of seconds. Protective functions used to detect this condition are armed when the generator is taken out of service. The following schemes have been used:

- Directional overcurrent
- Frequency-supervised overcurrent
- Distance protection
- Voltage-supervised overcurrent
- Breaker auxiliary contacts scheme with overcurrent

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

3.3.4.5 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 an abnormality that can be monitored and protected against. 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 operates incorrectly.

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

The following can cause overexcitation:

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 failures

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

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

3.3.4.6 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. This is dependent 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. There are two ratings given; the I2 continuous capability, and the short time capability (I2)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.

3.3.4.7 Loss of Synchronism (Out of Step)

This abnormal operation occurs when the generator loses synchronism with the system and/or other synchronous machines it is connected to. With large utility-type generators, sizes and per-unit reactance have increased, and their inertia constantly have decreased. This causes the critical clearing times of circuit breakers to be reduced to allow the generator to maintain synchronism for faults close to the facility.

Other abnormalities such as low voltage, reduced or loss of machine excitation, and some switching operations can be causes of the generator losing synchronism.

Depending on the size of the generator, the 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.

3.3.4.8 Circuit Breaker Failure to Open

Circuit breaker failure to open during any type of unit shut down, including normal, emergency or protective trip, can result in unit motoring and potentially lead to catastrophic failure of both generator and its prime mover. Generator breaker failure relays are used to provide back up protection against motoring in such an event. The following elements need be considered during the design of the circuit breaker failure relay at power generation stations to ensure the benefit of this relay.

A. During normal unit shut down event, the amplitude of the current through the breaker can be very small for a motoring condition. The breaker failure relay that solely relies on the motoring current level as an indication on the status of circuit breaker, may fail to initiate due to low level current. A steam turbine, for example, has a typical motoring power range of 0.5% to 3.0% of rated power. To overcome this limitation, mechanical indication of the breaker status needs be added to the breaker failure scheme. The breaker failure initiate signal is supervised by two measures: detectable current is flowing OR the breaker mechanical auxiliary contact still indicates that the breaker is closed. Either of these conditions can indicate that the breaker is closed to declare a breaker failure event and trip backup breakers.

B. An ideal breaker failure relay should be completely independent of any primary protection that will trigger breaker to operate at the first place. In doing so, any failure of components in the primary protection such as failure of the relay to detect fault, failure of the control circuit to communicate the trip signal to circuit breaker, failure of trip coil to operate, loss of DC source to the failed circuit breaker, won't result in an inability of breaker failure relay initiation.

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 over-current relay is connected to receive differential current in its operating coil circuit and neutral current in its polarizing circuit. The relay is set so 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:

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.

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.

3. Subharmonic voltage injection. This is applied if the generator does not generate sufficient third harmonic signal to apply any of the above schemes. In this method, a very low frequency (15 to 20 Hz) voltage signal is injected into the neutral grounding transformers and the resulting neutral current is monitored. Under normal conditions, a small level of current will flow at the subharmonic frequency. When a ground fault occurs anywhere in the winding of the generators or its associated bus work, the neutral current increases and the relay operates.

3.5 Condition Monitoring

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

3.5.2 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.

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

3.5.4 The following condition-monitoring systems are commercially available.

3.5.4.1 Stator Winding Temperature Sensors

Stator winding temperature sensors are the most common sensor provided on generators. They help to ensure that stator insulation does not deteriorate due to overheating. Typical temperature sensors used in large generators are resistance temperature detectors (RTDs) embedded between the top and bottom bars of form wound generators. Thermocouples may also be used instead of RTDs. Small and medium generators may use a thermistor or an overload relay instead of RTDs or thermocouples.

3.5.4.2 Rotor Winding Temperature Sensors

Rotor winding temperature sensors usually are only provided in large generators where the rotor windings are accessible through slip rings. The winding itself is used as an RTD to provide an indication of rotor winding temperature. In machines with brushless excitation systems, it is not possible to implement this form of rotor winding temperature sensing.

3.5.4.3 Core Temperature Sensors

Core temperature sensors are usually only provided in step iron area in both core ends since these are most susceptible areas to overheating due to leakage flux interception.

3.5.4.4 Core Monitor

Core monitors typically are installed in large hydrogen-cooled generators but have been applied in totally enclosed air-cooled generators. These systems continuously monitor the cooling gas stream to detect burning organic material. The presence of this material indicates severe overheating of rotor insulation, stator insulation, or core laminations has occurred. Some core monitor systems incorporate tagging compounds that are applied to different parts of the generator in the form of paint. The paint will vaporize and release various characteristic materials at a low temperature to warn of overheating before serious damage is done to insulation or core laminations. The location of overheating can be determined based on the type of material detected by the core monitor.

3.5.4.5 Air Gap Flux Probes

Air gap flux probes are widely applied in large synchronous generators. The probes are small search coils permanently installed in the air gap of the generator to measure rotor slot leakage flux. The waveform from the flux probes is used to identify shorted turns in the rotor winding. Readings from the air gap flux probes are taken approximately once a year to monitor rotor winding deterioration. Readings are also taken whenever bearing vibrations increase to confirm if the cause of the increased vibration is due to shorted rotor turns.

3.5.4.6 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 typically is applied to large form-wound generators rated 2.3 kV and above.

Stator slot couplers are also used on large generators 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 wiring is used as stator slot couplers.

3.5.4.7 Electromagnetic Interference (EMI) Testing

EMI is a noninvasive online frequency based method for detecting electrical and mechanical problems in generator insulation system such as partial discharge, arching and vibration. It can also be used to evaluate generator isolated phase bus conditions.

EMI signals are collected to produce a frequency spectrum with a split-core radio-frequency current transformer (RFCT) installed in the generator neutral or grounding cable. A typical EMI test survey will require 30 minutes to one hour to complete. A first time test can provide useful data as EMI test signatures can be compared to an established data base.

Each electrical or mechanical defect results in a distinctive frequency spectrum unique to the physical location and type of defect present within the electrical insulation system. Trending of EMI test results is most helpful to detect issues and for long-term analysis.

The use of both time domain PD detection and frequency-based EMI is optimum when evaluating a large generator.

3.5.4.8 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.

3.5.4.9 End-Winding Vibration Sensors

Due to cost and complexity, end-winding vibration sensors typically are only installed in large generators when there is reason to suspect a problem with the end windings. These sensors consist of fiber optic accelerometers that measure vibration of the end windings in the radial and circumferential directions.

3.5.4.10 Shaft Voltage and Current (SV&C) Sensors

Shaft voltage and current sensors measure the shaft voltage and leakage current from the generator shaft to ground. High levels of SV&C can come from a variety of sources including shaft rubs, residual magnetism, magnetic field asymmetries, winding faults, static discharge from the turbine, and excitation excitation/ electronic spikes and transients. They can cause damage to the integrity of the bearing and pedestal insulation as well as the efficiency of shaft grounding. Failure of this insulation can lead to arc damage to bearing surfaces and, eventually, bearing failure.

Bearing Babbit damage from high shaft current

Fig. 4. Examples of damage caused by high level of shaft current (photos courtesy of J. E. Timperley)

3.5.4.11 Hydrogen Dew Point Monitor

Hydrogen dew point monitors typically are used in large hydrogen-cooled generators fitted with 18Mn5Cr or 18Mn4Cr magnetic retaining rings. These monitors measure the dew point of hydrogen gas in the generator and can correct the dew point to ensure moisture does not condense on the retaining rings. Moisture will initiate stress corrosion cracking in magnetic retaining rings.

3.5.4.12 Hydrogen Purity Monitor

Hydrogen purity monitors are used in hydrogen cooled generators to monitor hydrogen purity in excess of 97%. A low concentration can result in windage losses, lower efficiencies and increase of mechanical stresses on the ventilation system. At atmospheric pressure, hydrogen concentrations from 4% to 74% of air forms an explosive mixture with air.

3.5.4.13 Ozone Monitor

Air decompose in the presence of electrical discharge to release ozone. Ozone can subsequently lead to accelerated degradation of insulation due to its oxidizing properties. Used in air-cooled generators, ozone monitors that measures high ozone level indicate presence of PD activity.

3.5.4.14 Hydrogen Seal Oil Pressure Detector

Integrity of the hydrogen seal might be compromised with low seal oil pressure, resulting in release of hydrogen from the generator. This result in overheating, increased vibration and possibly rubbing between journal and babbitt. Excessive seal oil pressure may flood the generator with oil. Measurement points should include seal oil to hydrogen differential, air-side seal oil, hydrogen-side seal oil and vacuum tank pressure for degassing entrapped hydrogen.

3.5.4.15 Hydrogen Seal Oil Temperature Detector

Changes in temperature of seal oil can result in changes in viscosity of the seal oil. Excessive temperature can result in increased oil flow and increased vibration level. Low temperature can cause reduced oil flow, loss of clearance and possible rub with the rotor.

4.0 REFERENCES

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Data Sheet 5-11, *Lightning and Surge Protection for Electrical Systems*
Data Sheet 5-19, *Switchgear and Circuit Breakers*
Data Sheet 5-20, *Electrical Testing*
Data Sheet 5-31, *Cables and Bus Bars*
Data Sheet 7-101, *Fire Protection for Steam Turbines and Electric Generators*
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APPENDIX A GLOSSARY OF TERMS

Base load unit: A generating unit operated at or near full capacity on a nearly continuous basis.

Bushing: The insulating structure that comprises the main terminals and through conductors, which connect to the generator winding. These conductors pass the machine current to the electrical system and provide a gas seal in hydrogen-cooled generators.

Direct-connected generator: A generator that is directly connected to a power distribution system through a circuit breaker, generally without a transformer. This arrangement is typical of industrial co-generation.

EL-CID: Electromagnetic Core Imperfection Detector. This detector makes use of a much lower excitation level than is used with a Core Loop Test, approximately 4% of rated flux. A special pickup coil "Chattock Potentiometer" is used to sense and measure the magneto motive force (mmf) between the top teeth of the stator core, and to detect any low-level fault currents in the core as it is excited with the low-level flux. The test is performed across adjacent teeth axially along the core. A current plot in milliamperes is recorded along the axial length of the core.

Excitation system: Equipment that provides and produces field current for a synchronous machine, including all power, regulating control, and some electrical protection elements.

Exciter: Equipment that provides field current for purposes of exciting the synchronous machine.

FM Approved: Products and services that have satisfied the criteria for Approval by FM Approvals. Refer to the *Approval Guide*, an online resource of FM Approvals, for a complete list of products and services that are FM Approved.

Field winding: The winding on the rotating element of a synchronous machine that provides the main electromagnetic field of the machine.

Generator: A machine that produces electrical power from mechanical power (Electromechanical Energy Converter).

Peak load unit: A generating unit operated for quick response to meet the maximum load demand periods.

Power factor: The ratio of the active power in watts to the volt-amperes. It is also used as a rating of the generator based on capability, i.e., the power factor rating defines the amount of reactive power capability without infringing on the rated real power output.

Capability curve: The synchronous machine rating curve based on real and reactive power loading. The capability is based on thermal limits on various components, operating limits, and gas pressures of the machine. It is normally plotted on a graph of Watts versus Vars.

Retaining ring: The mechanical structure on the rotor that surrounds the field winding and other components to restrain radial movement due to centrifugal action. Generally, this is the highest mechanically stressed component on the generator.

Rotor: The rotor component of an electric generator.

Stator: The stationary active parts of a rotating machine. This includes the stationary portion of the magnetic circuit (stator core) and the associated electrical winding and leads.

Stator core (stator iron): the stationary magnetic part of a rotating machine. It is comprised of many laminations of magnetic steel assembled together, which contain the stator winding. It also provides the magnetic flux path.

Stator winding: The electrical winding contained in the stator of the electric generator. It is connected via bushings or cable terminations to the electrical system.

Synchronism: When connected alternating current systems, machines, or some combination operate at the same frequency, and where the phase-angle displacements between voltages in them are constant, or vary a steady and stable average value.

Turbine: A prime mover of the electric generator used to convert heat energy into mechanical power.

Unit-connected generator: A generator that is part of a unit that normally operates as a single source of power and is self sufficient with regard to its auxiliary system power needs. It is generally connected to the utility transmission system via a main step-up transformer through a dedicated breaker or breakers.

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 2026. Interim revision. Minor editorial changes were made.

October 2025. Interim revision. Editorial changes were made to improve clarity.

April 2025. Interim revision with the following main changes:

A. Added guidance for evaluation of Operators, specific to generator risk control.

B. Revised guidance on high-pot electrical testing to address recent loss experience to recommend rewinding or replacement for generators with significant pre-existing conditions such as a history of vibration or issues with looseness.

July 2024. Interim revision. Minor editorial changes were made.

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

July 2022. Interim revision. The following significant changes were made:

A. Added recommended commissioning tests for new generators and generators that have had a major modification or repair.

B. Added guidance on generators with flexible operation.

C. Revised Table 3, Generator Testing, with recommended tests subject to generator size (added a 20 MW threshold).

January 2022. Interim revision. Minor editorial changes were made.

July 2021. Interim revision. Clarified equipment contingency planning guidance.

April 2021. Interim revision. Minor editorial changes were made.

October 2020. Interim revision. Minor editorial changes were made.

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

April 2020. Interim revision. Section 4.2, *References*, was updated.

October 2019. Interim revision. Minor editorial changes were made.

April 2019. Interim revision. Minor editorial changes were made.

January 2019. Interim revision. Minor clarifications were made in Table 2.

January 2018. Major revision with the following significant changes:

A. Simplified fire protection guidance.

B. Updated electrical protection recommendations.

C. Updated recommendations for generators with condition-based maintenance strategy to incorporate robotic inspection.

D. Improved guidance on generator maintenance to factor in operating conditions, maintenance, inspection history, etc.

January 2016. Interim revision. Editorial changes were made.

May 2010. Minor editorial changes were made for this revision.

June 2005. The data sheet was completely restructured, with substantial changes made to the content.

March 2005. The data sheet was completely restructured, with substantial changes made to the content.

January 2005. Clarification was made to the recommendation 2.1.1.

September 2003. Recommendation 2.3.3.1, on contingency plans for generators whose failure would cause serious production interruption, was added. A revision was made in Section 2.4.1 that refered to nonmagnetic retaining rings. Recommendation 2.3.2.6 for overvoltage testing was revised.

September 2002. This revision superseded January 2001 version. The data sheet was substantially restructured and material reflecting current industry best practices and specific concerns was added along with guidance on how to accommodate Condition-Based Maintenance Programs with regard to Loss Prevention.

Additions included the following:

1. Generator Inspection Guidance

2. Generator Circuit Breakers

3. Generator Grounding and Concerns with Stator Core Damage

4. Additional Generator Hazards

5. Glossary of Terms

6. Comprehensive Bibliography

7. Failure Mode List Summary Table

8. Additional Equipment Alerts

9. Equipment Alert 2.4.6 addressing ASEA's Stal-Laval generators was changed to correct the technical content.

January 2001. This was a new data sheet incorporating the electric generator portions of Data Sheet 13-3, *Utility Steam Turbine-Generators* (October 1998) and Data Sheet 13-11, *Steam Turbines Driving Generators: Industrial Applications* (September 1998).

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