STEAM TURBINES

Table of Contents

Page

List of Figures

List of Tables

1.0 SCOPE

This data sheet provides loss prevention recommendations for steam turbines used to drive generators for electrical power, mechanical equipment, and mechanical-drive applications. The recommendations apply to all steam turbine types, models, and sizes unless otherwise specified.

For the purposes of this data sheet, a steam turbine is defined as the stationary and rotating components, including valves, steam piping, pipe support, monitoring systems, control systems, and all associated systems, up to the driven-object coupling. Refer to Appendix A for a definition of “Steam Turbine Types” to differentiate between generator-drive, general purpose, and special purpose mechanical-drive steam turbines.

For fire-related information on steam turbine generators, refer to Data Sheet 7-101, *Fire Protection for Steam Turbines and Electric Generators.*

1.1 Changes

April 2025. Interim revision. Clarifications were made to the following:

A. Provided clarifications for steam turbine shaft driven lube oil pumps.

B. Provided clarification - non-return valves are not required for back pressure steam turbine exhaust lines.

2.0 LOSS PREVENTION RECOMMENDATIONS

2.1 Equipment and Processes

2.1.1 Protective Devices

Provide the protective devices, alarms, and trips listed in Table 2.1.1-1 (generator-drive steam turbines) and Table 2.1.1-2 (mechanical-drive steam turbines). For alarm and trip settings, adhere to the original equipment manufacturers (OEM) user manual and specifications.

Table 2.1.1-1. Recommendations for Generator-Drive Steam Turbine Protective Devices, Alarms, and Trips

Protective Device	*Actuated Device*	*Alarm*	*Trip*
1. Emergency electronic overspeed trip	Annunciator, shut emergency stopvalve, sequential trip	X	X
2. Nonreturn valves in extraction lines	None	Passive Protection[Note 1]	
3. Rotor axial position monitoring by proximity probes, micrometer measurement, or temperature in thrust bearing pads	Annunciator, shut emergency stopvalve, sequential trip	X	X
4a. Low oil-pressure sensor, main lube-oil pump	Annunciator, start auxiliary oil pump	X	
4b. Low oil-pressure sensor, auxiliary lube-oil pump	Annunciator, shut emergency stop valve start emergency oil pump, sequential trip	X	X
4c. Low oil-pressure sensor, emergency lube-oil pump	Annunciator, shut emergency stopvalve, sequential trip	X	X
5. Low oil-level sensor in lube oil tank	Annunciator, shut emergency stopvalve, sequential trip	X	X
6. High oil-level sensor in tank	Annunciator	X	
7. Condenser low vacuum/high condenser back pressure	Annunciator, shut emergency stopvalve, sequential trip, operational procedure to prevent operating in OEM avoidance zones	X	X
8a. High level switches on steam line drain pots	Annunciator, open drain valves	X	
8b. High-high level switches on all steam line drain pots	Annunciator, open drain valves	X	
9a. High level switches on all feedwater heaters (closed and deaerating heaters)	Annunciator, open high level drain valve to the condenser or receiver	X	
9b. High-high level switches on all feedwater heaters (closed and deaerating heaters)	Annunciator, power-operated block valve in extraction line, power-operated drain valve on the turbine side of the NRV, **or**, automatic shutoff valves on all sources of water to feedwater heater	X	
10a. High water-level switches on boiler drums	Annunciator, operational procedure to correct water level	X	
10b. High-high water-level switches on boiler Drums	Shut emergency stop valve, sequential trip		X
11. High oil-temperature sensor, located at either lube-oil header, supply or bearing drains	Annunciator	X	
12a. Turbine thrust bearing thermocouple, high temperature, metal temperature, and/or drain lube-oil temperature	Annunciator, shut emergency stopvalve, sequential trip. For existing installations, an operational procedure in place if no trip is provided.	X	X
12b. Turbine journal bearing thermocouples, high temperature, embedded RTDs in all Babbitt bearings and/or thermocouple in the bearing oil drain lines.	Annunciator, shut emergency stopvalve, sequential trip. For existing installations, an operational procedure in place if no trip is provided.	X	X
13. Vibration monitoring by hand-held or fixed instrumentation (≤25 MW)	Annunciator, and senior operations notification procedure	X	
14. High vibration instrumentation on bearings including the generator and gearbox unit, exceeds set point (>25 MW)	Annunciator, shut emergency stopvalve, sequential trip, and senior operations notification procedure	X	X
15. Lube-oil filter differential pressure	Annunciator, pressure switches, differential pressure (ΔP) across the filter	X	
16. High temperature on turbine exhaust (backpressure or condensing)	Annunciator, shut emergency stop valve, sequential trip, operational procedure to prevent operating in OEM avoidance zones	X	X
17. High temperature on steam extraction lines	Annunciator, shut emergency stop valve, sequential trip	X	X

Table 2.1.1-1 Recommendations for Generator-Drive Steam Turbine Protective Devices, Alarms, and Trips (continued)

Protective Device	*Actuated Device*	*Alarm*	*Trip*
18. High pressure on extraction steam lines	Annunciator, shut emergency stop valve, sequential trip	X	X
19. Steam inlet steam minimum temperature (superheating) or steam inlet temperature decreasing gradient	Annunciator, shut emergency stop valve, sequential trip	X	X
20. False trip detection: turbine tripped and power generation >0	Annunciator, operational procedure to shut down the boiler and close all steam sources to the turbines before opening the generator circuit breaker (GCB)	X	
21. Motoring detection: turbine tripped and power generation < 0 or turbine control valve closed and power generation < 0	Annunciator, operational procedure to open the GCB	X	
22. Thermocouples in main steam line detecting temperature differential above OEM limits prevent water induction	Shut emergency stop valve. sequential trip		X
23. Casing temperature differential, when differential between top and bottom exceeds OEM limits (radial)	Annunciator, operating procedure to prevent rotor to casing rubs	X	
24. High differential expansion between rotor and stationary components (axial) exceeds OEM limits	Annunciator	X	
25. High-high differential expansion between rotor and stationary components (axial) exceeds OEM limits	Annunciator, operating procedure to prevent rotor to casing rubs	X	
26. DC emergency lube oil pump motor thermal overload protection	Annunciator	X	

Note 1. Passive protection refers to a component or configuration that provides protection without an annunciator (audible, visual alarm) and without a turbine trip.

Table 2.1.1-2. Recommendations for Mechanical-Drive Steam Turbine Protective Devices, Alarms, and Trips

Protective Device	*Actuated Device*	*Alarm*	*Trip*
1. Emergency overspeed trip (mechanical or electronic)	Annunciator, shut emergency stop valve, turbine trip	X	X
2. Nonreturn valves in extraction steam lines	None	Passive Protection Note 1	
3. Thrust bearing axial position monitoring by means of proximity probes, micrometer measurement or temperature in thrust bearing pads	Annunciator, shut emergency stop valve, turbine trip	X	X
3a. Low oil-pressure sensor, main lube-oil pump	Annunciator, start auxiliary oil pump	X	
3b. Low oil-pressure sensor, auxiliary lube-oil pump	Annunciator, shut emergency stop off valve and start emergency oil pump, turbine trip	X	X
3c. Low oil-pressure sensor, emergency lube oil pump	Annunciator, shut emergency stop valve, turbine trip	X	X
4. Low oil-level sensor in tank or bearing pedestal (gravity systems or ring oiler system)	Annunciator, shut emergency stop valve, turbine trip	X	X
5. High oil level sensor in tank or bearing pedestal (gravity systems or ring oiler system)	Annunciator	X	
6. Condenser low vacuum	Annunciator, shut emergency stop valve, turbine trip	X	X
7. Automatic condensate traps at low points and at valves in main steam line	None	Passive Protection Note 1	
8a. High water level switches on boiler drums	Annunciator, and senior operations notification procedure	X	
8b. High-high water level switches on boiler drums	Shut emergency shutoff valve, turbine trip		X
9a. Vibration monitoring by hand-held or installed instrumentation (<6,700 hp [4996 kW])	Annunciator, and senior operations notification procedure	X	
9b. High vibration instrumentation on all bearings including the gearbox (>6,700 hp [4996 kW])	Annunciator, shut emergency stop valve, senior operations notification procedure, turbine trip	X	X
10. Lube-oil filters	Pressure switches, differential pressure (ΔP) across the filter	X	
11. Pressure-relief valve between turbine and any discharge block valve (non-condensing turbines)	None	Passive Protection Note 1	
12. Thermocouples in main steam line (prevent water induction) Note 2 (>33,500 hp [24,981 kW])	Annunciator, shut emergency stop valve if temperature differential exceeds OEM limits, turbine trip	X	X
13. Casing temperature differential between top and bottom exceeds OEM limit (>33,500 hp [24,981 kW])	Annunciator, operating procedure to prevent rotor to casing rubs		X
14. High differential expansion between rotor and stationary components (axial) exceeds OEM limits (>33,500 hp [24,981 kW])	Annunciator	X	
15. High-High differential expansion between rotor and stationary components (axial) exceeds OEM limits (>33,500 hp [24,981 kW])	Annunciator, operating procedure to prevent rotor to casing rubs	X	
16. High oil-temperature sensor, located at either lube-oil header, supply or bearing drains	Annunciator, and senior operations notification procedure	X	

Note 1. Passive protection refers to a component or configuration that provides protection without an annunciator (audible, visual alarm) and without a turbine trip.
Note 2. At least a low-temperature alarm and trip for inlet steam should be provided in accordance with OEM recommendation. For existing turbines, a simple alarm of low inlet steam temperature is acceptable, per OEM recommendation to prevent water induction.

2.1.2 Turbine Speed-Control/Overspeed Protection Systems

2.1.2.1 Redundancy is an essential factor for the reliability of the overspeed protection system. Redundancy in an electronic overspeed protection system is highly recommended and can be built into:

- the speed-sensing circuit with multiple probes, threshold detection and comparison with redundant processors
- trip control and command using redundant voting logic
- trip solenoids that are fail safe (deenergize to trip)
- Loss of speed signal

Note: Regarding loss of speed signal, DC power or control power is considered a failure signal in 2-out-of-3 voting logic.

Triple redundant electronic systems having two-out-three voting logic, testing capability, and self-diagnostic loop integrity should be installed.

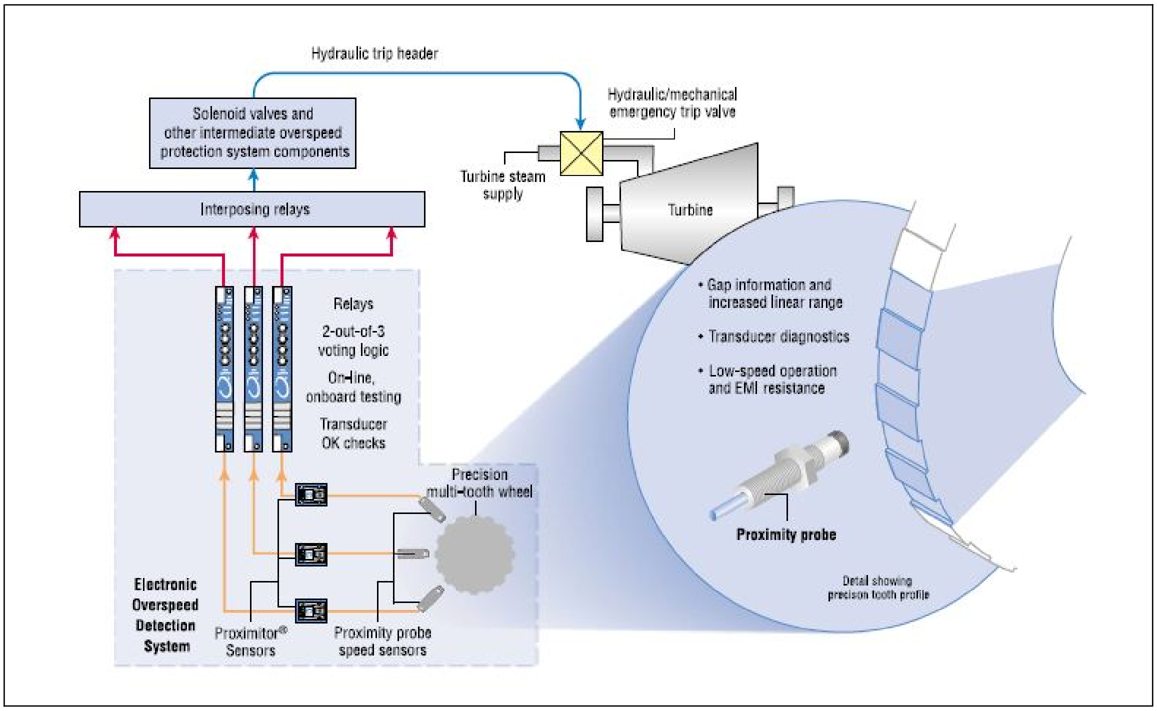

Fig. 2.1.2.1. Typical triple redundant electronic overspeed detection system
(Bently Nevada-General Electric Company, all rights reserved, used with permission)

2.1.2.2 Triple Redundant Electronic Overspeed Systems

2.1.2.2.1 Base the system on three independent measuring circuits and two-out-of-three voting logic. Figure 2.1.2.1 shows a typical triple redundant system and its components.

2.1.2.2.2 Alarm when either of the following occurs:

A. An overspeed condition is sensed by any one circuit, or

B. A sensor, power supply, or logic device in any circuit fails.

2.1.2.2.3 Trip the turbine when either of the following occurs:

A. An overspeed condition is sensed by two out of three circuits, or

B. A speed sensor, power supply, or logic circuit in two out of three circuits fails.

2.1.2.2.4 Ensure the speed sensors used as inputs to the electronic overspeed detection system are not shared with any other system.

2.1.2.2.5 Provide the system with fully redundant power supplies.

2.1.2.3 Fault-Tolerant Electronic Overspeed Systems

2.1.2.3.1 Provide at least two, and preferably three, independent, separately powered sensors, logic solvers, and trip elements to minimize the probability of random hardware failures in a single train disabling the protective functions. Refer to Data Sheet 7-45, *Safety controls, Alarms and Interlocks* for further guidance. The system should be designed to be single failure tolerant (it cannot use a 2 out of 2 logic, for instance). Do not use any trip system that could be subjected to common mode failure in the speed-sensing circuitry, such as a single-trip system, or a two-trip system having a common power supply.

2.1.2.4 Mechanical Overspeed Systems

2.1.2.4.1 For steam turbines, where a mechanical overspeed protection system is used, verify the following:

A. Trip bolts, plungers, cantilever systems, and trip rings are fixed to the rotor and rotate with it.

B. Trip devices are set to actuate trip levers in accordance with OEM recommendations. See Figure 2.1.2.4.1-1.

C. Ensure trip levers are connected to emergency trip mechanisms. Upon triggering, the emergency trip system should trip all emergency and control valves and emergency devices, commencing the unit shutdown process. See Figure 2.1.2.4.1-1 and Figure 2.1.2.4.1-2.

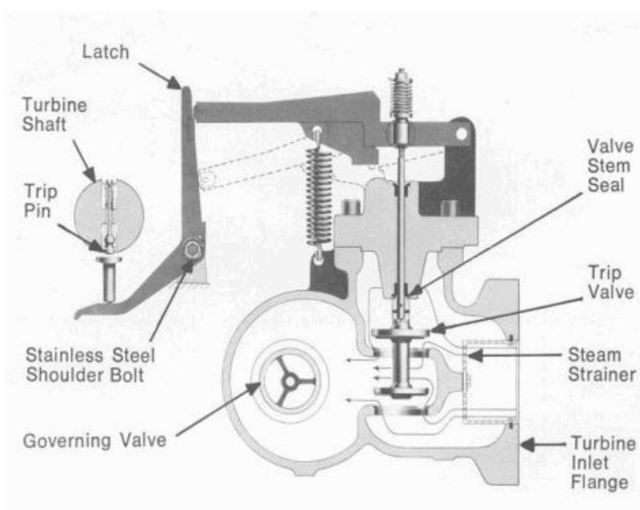

Fig. 2.1.2.4.1-1. Simplified mechanical bolt mechanism (Elliott Company, all rights reserved, used with permission)

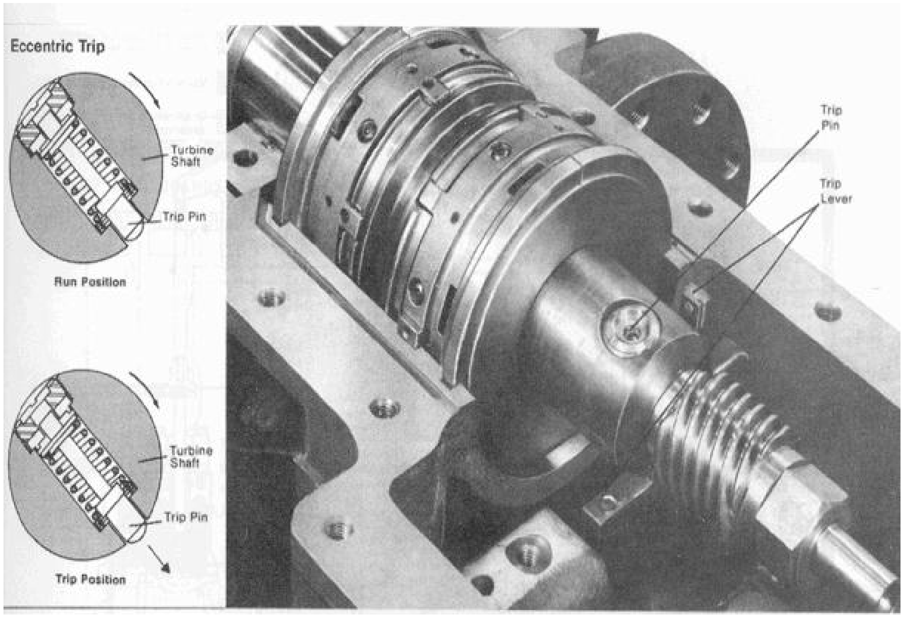

Fig. 2.1.2.4.1-2. Mechanical bolt mechanism (Elliott Company, all rights reserved, used with permission)

2.1.3 Lubrication-Oil Protection Systems

Equip steam turbines with oil lubrication systems to provide sufficient lubrication in accordance with the OEM's instructions. Figures 2.1.3 and 2.1.3.1.6 show typical oil systems and their components.

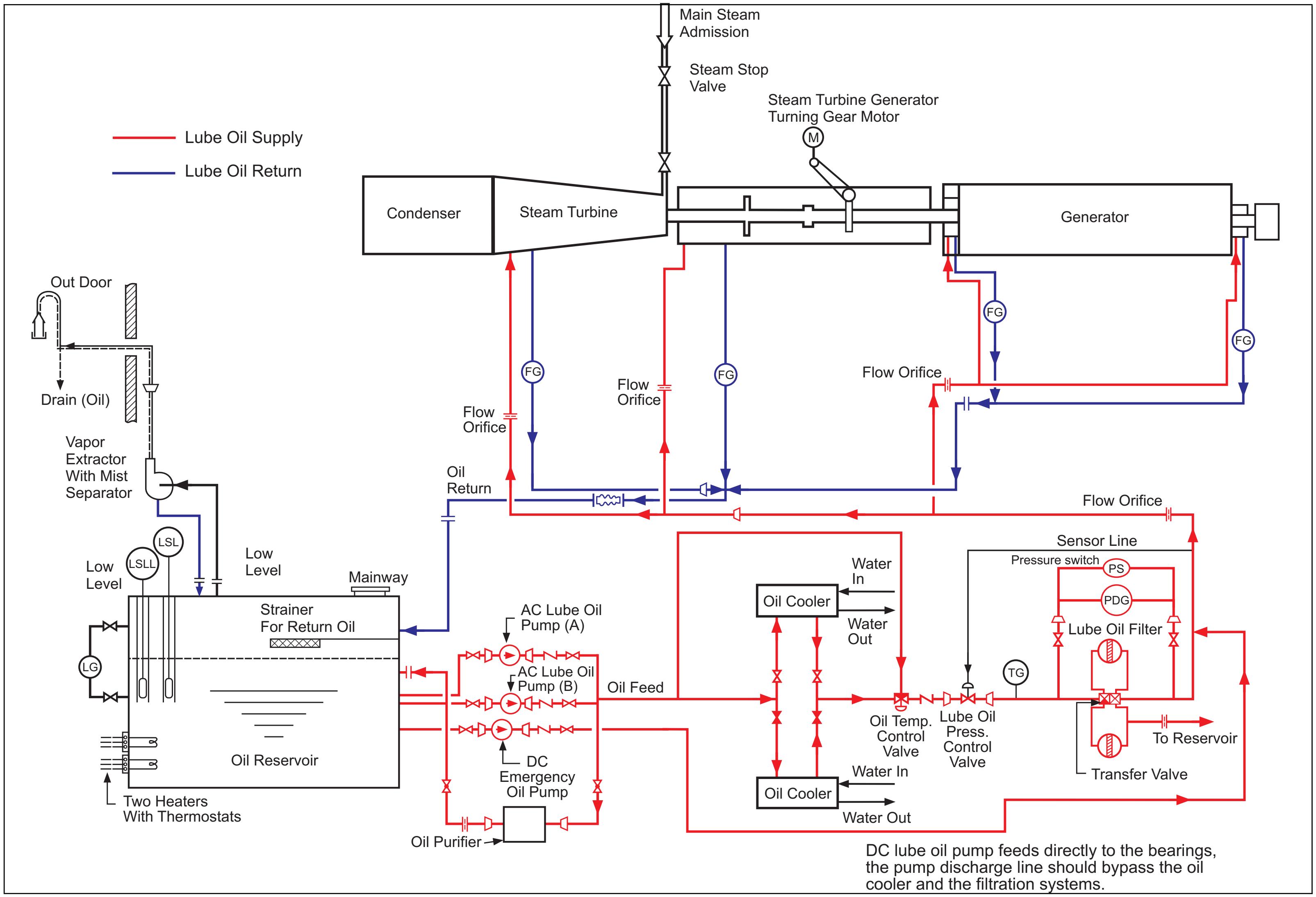

Fig. 2.1.3. Typical steam turbine lubricating system

2.1.3.1 Lube and Seal Oil System

2.1.3.1.1 Lube and seal oil systems may service either a single component or a train of components. A train of turbomachinery may include components such as a steam turbine, gas turbine, generator, compressors, gearbox, coupling, etc. If there is a common lube oil and/or seal oil system for these components, ensure the oil and the systems used are compatible with all of the components serviced.

2.1.3.1.2 Provide a separate source of oil for each train supplied.

2.1.3.1.3 Provide an emergency lube oil and seal oil system if it is required to safely shut down the unit if the primary oil supply is interrupted.

2.1.3.1.4 Ensure the emergency lube oil system configuration is inherently resilient and that no single failure can result in a loss of equipment lubrication. Ensure the emergency oil bypasses coolers and filters and feeds the bearings directly. Evaluate control circuits, electric power and/or piping systems to eliminate single points of failure.

A. When rotating equipment requires emergency lucrication during shutdown and a DC pump is used, do the following:

1. To increase the reliability of the lube oil supply, provide separate DC power supply systems, including one separate DC bus for the emergency lube and generator seal oil, and one separate DC bus for the DCS control system uninterrupted power supply (UPS) and the protective relays and circuit breakers.
    a. Make the auxiliary AC lube oil pump fail-safe (i.e., de-energize to automatically start the auxiliary AC pump on the loss of DC power).
2. Design the capacity of the battery bank powering the DC lube oil pump such that the battery can supply the DC pump for the duration of the coast-down time of the turbine train, plus 30 additional minutes. Reference Data Sheet 5-28, *DC Battery Systems*, for guidance on system design and sizing considerations. Refer to Appendix A, Glossary of Terms, for a definition of “coast down time.”
3. Provide a low-voltage alarm for DC buses at a continuously monitored location. Refer to Data Sheet 5-28, *DC Battery Systems*, for more details.
    a. The accumulators on lube-oil, control-oil, and seal-oil lines should be properly charged to prevent shocks and inadvertent trips.
4. Do not wire the DC emergency lube-oil pump motor thermal overload protective devices to trip the motor, but only to sound the alarm in an operator-manned control room.
    a. Recommend that thermal overload alarms are logged into the maintenance management system as a high priority; so the DC motor can be tested, repaired or replaced as soon as practical.
    b. In the event of motor thermal overload, allow the DC motor to run to failure rather than tripping the emergency lube oil pump and damaging the turbine and generator bearings
5. Provide a DC emergency lube-oil pump starter that is fail-safe (i.e., automatically starts the pump when AC power to main lube oil pump, PLC, controlling hardware, or communication network is lost).
6. Provide a means for testing the automatic start functionality of the DC lube oil pump. Pressure drop via the pressure-sensing line independent of lube oil system pressure is the preferred arrangement. Refer to the section on Emergency Lube Oil System Testing for more details.
7. Provide a means (e.g., check valve) within the normal lube oil supply line to ensure one-way flow, so that under emergency conditions, when the emergency lube oil pump is operating, the emergency supply cannot be short-circuited back into the lube-oil tank.
8. When the turning gear is not available for normal operation, provide an emergency operating procedure to manually rotate a hot rotor to prevent rotor bowing.
9. Recommend adding an alarm to prevent starting the turbine whenever the emergency lube oil pump breaker is not in the “Auto” position.
10. Reference Data Sheet 7-109, *Fuel Fired Thermal Electric Power Generation Facilities*, for recommended startup permissive Guidance for lube oil systems

B. If rotating equipment requires lubrication during shutdown and a steam- driven pump is used for emergency shutdown, ensure steam is available by locking open the isolation valve(s) between the steam source and the pump governor valve. Evaluate if any scenario such as a boiler trip or the closing of an upstream valve could cause starvation of steam to the turbine oil pump. Ensure the steam line is continuously drained to avoid a water hammer, which could damage the steam-driven emergency oil pump.

C. If rotating equipment requires lubrication during shutdown and a rundown tank is used, ensure any isolating valves are kept locked in the open position.

D. If rotating equipment requires lubrication during shutdown and an AC or DC lube-oil pump is powered by an internal combustion engine emergency or standby power system, ensure it is operated and maintained per Data Sheet 5-23, *Design and Protection for Emergency and Standby Power Systems*, and inspected, tested and maintained per Data Sheet 13-26, *Internal Combustion Engines*, and Data Sheet 5-20, *Electrical Testing,* for the generator and automatic transfer switches. Ensure the circuit breaker connecting the internal combustion engine backup generator is left in auto mode when in standby so it can start automatically as intended.

E. Recommend that generator drive steam turbines with shaft-driven main lube oil pumps are equipped with an AC lube oil pump for startup and shutdown, and a DC lube oil pump for emergency shutdown and turning gear operation. The shaft-driven main lube oil pumps are not capable of providing sufficient bearing lubrication throughout the entire rotor coast-down period and turning gear. A DC emergency lube oil pump is not required if emergency oil supply is provided by an auxiliary AC pump powered by an emergency/standby generator, a gravity rundown tank or a steam driven pump that starts automatically upon the loss of AC power.

2.1.3.1.5 Lube-oil temperature is a critical operating parameter and if the machine operates for an extended period of time at elevated temperatures the bearings can be damaged. Provide high lube-oil temperature or bearing metal temperature trips as follows:

A. For a constantly attended unit: Provide an alarm on high lube-oil or bearing metal temperature and have a procedure in place for the operator to respond promptly to diagnose the source of the high temperature. If the high temperature condition cannot be corrected and the oil temperature reaches the design limit, direct the operator to trip the unit, or have the unit automatically trip when the temperature reaches the trip set point.

B. For an unattended unit: If the oil or bearing metal temperature reaches the design set point, have the unit automatically trip.

2.1.3.1.6 If procedurally acceptable, lock open all lube-oil system valves including impulse lines for instrumentation that represent single points of failure, to prevent inadvertent closure. Include valve positions in standard and emergency operating procedures, as well as the respective P&IDs. Refer to Figure 2.1.3.1.6 for a simplified drawing of how this is applicable under normal operation.

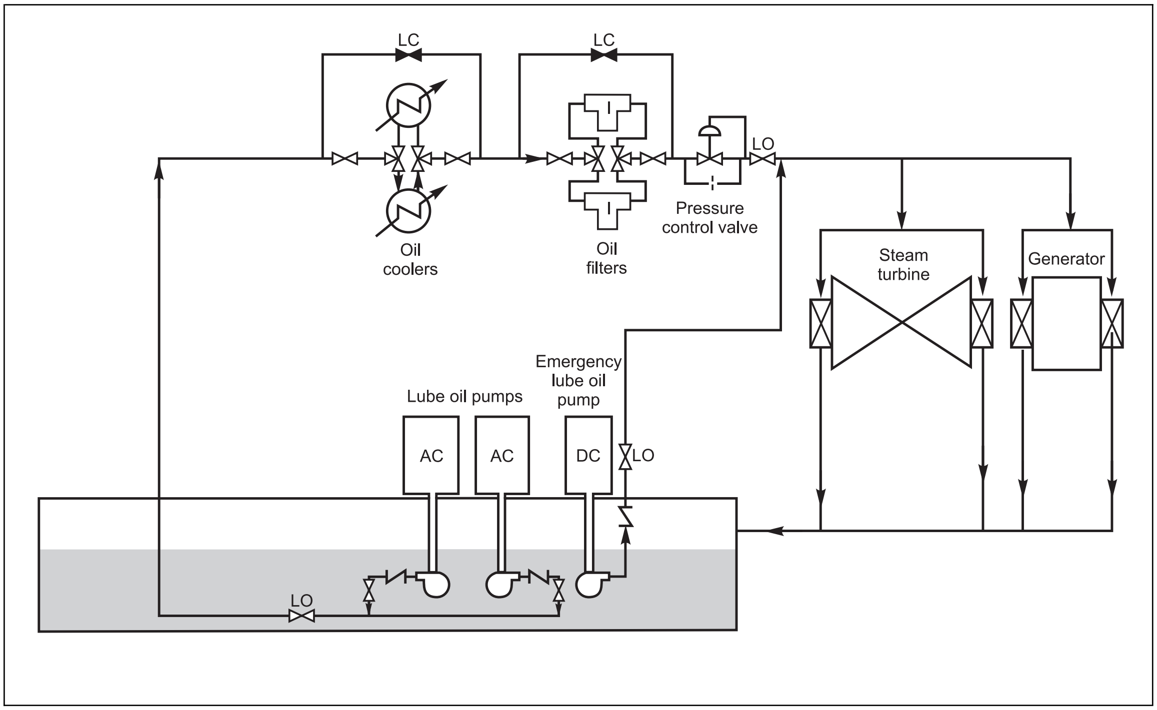

Fig. 2.1.3.1.6. Simplified lube-oil system with typical considerations for locked open (LO) and locked closed (LC) valves

2.1.3.1.7 Mechanical-Drive Steam Turbine Lubrication

A. Ring oil lubrication systems: Provide low oil-level sensors on each bearing sump with alarm and trip functions.

B. Saddle pump/steam turbine shaft driven lubrication: Provide gravity rundown tanks for adequate lubrication during the emergency coast down period of the turbine. Mount tanks above the lubrication pump and size them to provide the system with gravity lube-oil flow after a trip. Provide an AC Pump for initial lubrication at startup.

C. Force-feed pressurized pump lubrication:

1. For shaft-driven main oil pump and AC motor auxiliary pump systems, provide an auxiliary DC emergency lube-oil pump or an additional lube-oil supply by a gravity rundown tank. Mount these tanks above the lubrication pump and size them to provide the system with gravity lube-oil flow after a trip, during the emergency coast down period of the steam turbine and turning gear. A DC emergency lube oil pump is not required if emergency oil supply is provided by an auxiliary AC pump powered by an emergency/standby generator, a gravity rundown tank or a steam driven pump that starts automatically upon the loss of AC power.

2. For lubrication systems with an AC motor main and an AC motor auxiliary lubrication pump (which may be DC power inverted to AC power), provide an auxiliary DC emergency lube-oil pump or an additional lube-oil supply by a gravity rundown tank.

3. Provide the low oil-pressure and main reservoir and gravity tank low oil-level sensors with alarm and trip functions.

2.1.3.2 Major Components for Online Testing

Install all necessary components, devices, and instruments to provide the lubrication fluid necessary to meet the operation requirement and to permit testing of auxiliary and emergency lube-oil pumps.

2.1.4 Bearing Protection

2.1.4.1 Provide bearings with embedded metal temperature thermocouple detection devices in the Babbitt material of the bearings, if accessible, or temperature thermocouple in the lube-oil drain return lines.

2.1.4.2 Equip turbine thrust bearings with axial displacement monitoring or thrust bearing pad temperature to provide detection, alarm, and trip. A thrust position monitor or thermocouples in the thrust bearing pads will provide early warning of thrust bearing failure due to a shift in axial position or increased thrust bearing temperature. A thrust position monitor continuously measures the thrust bearing movement and monitors the rotor axial position within the thrust bearing relative to the axial clearances within the machine, while thrust bearing pad temperature monitoring indicates excess wear by an increasing trend in temperature with alarm and trip settings.

2.1.4.3 Equip turbine journal bearing with vibration proximity probes/transducers to monitor the vibration of the rotor relative to the bearing. The measurement of the shaft displacement in two radial directions is used to provide alarm and trip.

2.1.4.4 Do not provide a remote reset function of vibration trips for remotely operated units.

2.1.4.5 Use vibration monitoring systems that have self-diagnostic capabilities.

2.1.5 Hydraulic/Control-Oil Supply System

Equip steam turbines with hydraulic/control-oil systems to provide high-pressure fluid necessary to meet operating requirements.

2.1.5.1 Install all necessary components, devices, and instruments to provide the high-pressure fluid necessary to meet the hydraulic system requirements and permit testing of system components. See Figure 2.1.5.1.

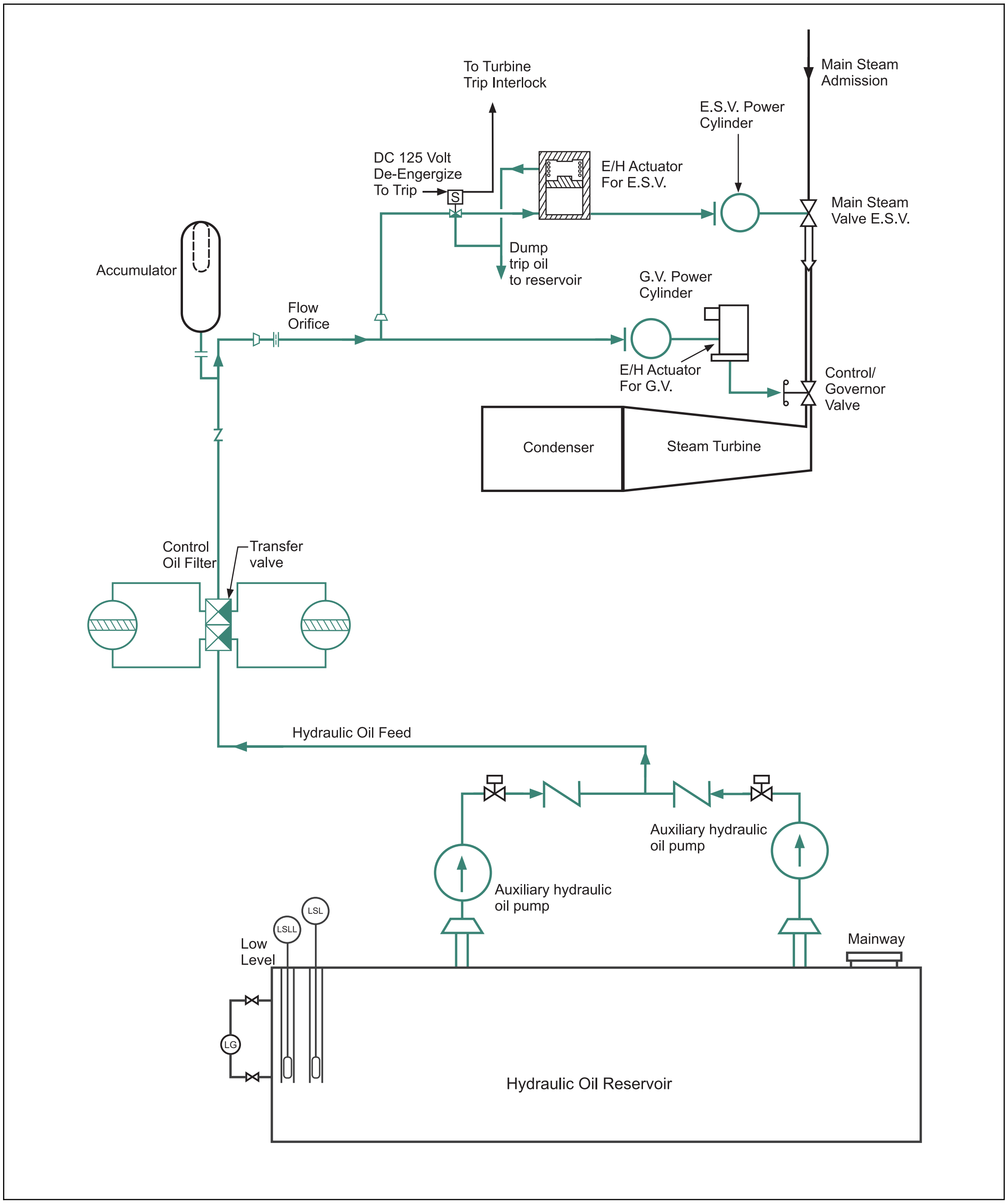

Fig. 2.1.5.1. Typical hydraulic control-oil supply system

2.1.5.2 Provide two auxiliary high-pressure-type pumps driven by electrical motor ac power. Put one pump in service as the primary pump and keep the second pump as a backup.

2.1.5.3 Ensure a differential pressure gage and pressure switch is available to indicate the oil pressure across the filters. Change the filter element when the gauge indicates high differential pressure, or annually, whichever occurs first. Refer to the OEM user manual for the correct setting and maintenance procedure for the filtration system.

2.1.5.4 Lube oil can be used as the high-pressure hydraulic/control oil to provide the necessary fluid to meet the turbine hydraulic system requirements.

2.1.6 Water Quality/Steam Purity Monitoring Systems

2.1.6.1 Water Quality

Water quality is an essential factor of steam purity. It involves treatment of raw (make-up) water, deaeration, automatic dumping/treatment of return condensate, addition of chemicals, and blowdown rates. Proper water treatment enhances reliability and efficiency, increases equipment service life, and reduces maintenance.

2.1.6.1.1 Provide a demineralization water-treatment facility, and use purified/treated water in steam production.

2.1.6.1.2 Monitor the water quality per the unit specific specifications in the OEM manual for the steam turbine model.

2.1.6.1.3 Ensure water treatment meets unit-specific specifications in the OEM manual for the steam turbine model. Ensure water is free of solid particles and contaminants.

2.1.6.1.4 Use the following recommendations to evaluate water treatment and adjust parameters to minimize contamination and possible damage to turbine components.

A. Provide continuous monitoring of feedwater for pH and conductivity. Alarm when operating limits are exceeded.

B. Provide continuous monitoring of boiler water (continuous blowdown) for pH and conductivity when chemical treatment is injected into the drum. Alarm when operating limits are exceeded.

C. Provide condensate monitoring (conductivity) and automatic dumps. Calibrate conductivity probes and function test automatic condensate dumps monthly.

D. Provide feedwater that is free of solid particles and contaminants for any attemperators.

2.1.6.2 Steam Purity and Steam quality

Steam purity can have a significant influence on turbine output, efficiency, availability, and service life. The steam impurity concentrations must be sufficiently controlled to prevent turbine component damage such as pitting, stress corrosion cracking, and corrosion fatigue.

2.1.6.2.1 Provide a steam-sampling panel, with complete sampling for all steam admission lines. Ensure steam purity is in accordance with OEM manual.

2.1.6.2.2 Follow the instructions of the OEM manual during the operation of the steam sampling system.

2.1.6.2.3 Take steam samples and analyze system integrity at every startup (after shutdown) and prior to introducing steam into the turbine.

2.1.6.2.4 Take steam samples and analyze system integrity per the turbine OEM's guidelines, and where no guidelines are provided, refer to Table 2.1.6.2.4, Steam Purity (Reference Guide).

2.1.6.2.5 Ensure steam purity/chemistry limits are in accordance with operating practices and specifications per the OEM manual.

2.1.6.2.6 Use the values in Table 2.1.6.2.4 as a guide for evaluating the contamination depositions to minimize possible corrosion damage to the turbine components.

2.1.6.2.7 Provide a low-temperature alarm and trip for inlet steam low superheat temperature if required by the turbine OEM. Thermocouples may be installed in the turbine or in the connecting steam piping at locations determined by the turbine manufacturer to assist in preventing water induction or cold steam from entering the turbine.

Follow the OEM's manual as the specifications vary according to the turbine design and application.

Table 2.1.6.2.4. Steam Purity (Reference Guide)

Steam Purity for Steam Turbine with Reheat System		
Target Parameter	**Sample**	**Normal**
Sodium, ppb	Continuous	≤3
Cation, conductivity µS/cm	Continuous	≤0.15
Conductivity	Continuous	≤0.25
Silica, ppb	Continuous	≤10
Chloride, ppb	Once per day	≤3
Sulfate, ppb	Once per day	≤3
Total organic carbon, ppb	Once per week	≤100
Steam Purity for Steam Turbine without Reheat System		
Target Parameter	**Sample**	**Normal**
Sodium, ppb	Continuous	≤6
Cation, conductivity µS/cm	Continuous	≤0.25
Conductivity	Continuous	≤0.45
Silica, ppb	Continuous	≤20
Chloride, ppb	Once per day	≤6
Sulfate, ppb	Once per day	≤6
Total organic carbon, ppb	Once per week	≤100
Steam Purity for General Purpose for Mechanical-Drive Steam Turbine[Note 1]		
Target Parameter	**Sample**	**Normal**
Sodium, ppb	Once per day & every startup	5-10
Cation, conductivity µS/cm	Once per day & every startup	0.1-0.3
Silica, ppb	Once per day & every startup	10-20
Chloride, ppb	Once per day& every startup	3-15
Sulfate, ppb	Once per day& every startup	10-20

Note 1. Verify steam purity is in accordance with OEM specification to prevent turbine component damage and sampled daily and at every startup.

2.1.7 Turbine Water Induction Damage Prevention

2.1.7.1 To prevent water from entering and damaging the turbine, adhere to the recommendations in ASME Standard TDP-1-2023, *Recommended Practices for Prevention of Water Damage to Steam Turbines used for Electric Generation: Fossil-Fuel Plants*. This standard is applicable to turbines used in conventional steam cycle, combined cycle, and cogeneration plants, and addresses damage due to water, wet steam, and cold steam backflow into a steam turbine (see Appendix A for the definition of ″cold steam″). This standard also provides guidance for mechanical-drive turbines.

2.1.7.2 For installations using a drum boiler, provide a high and a high-high water level sensor on the boiler drum, set to send an audible alarm to give the operator time to control feedwater flow, and a turbine trip before water induction into the turbine occurs.

2.1.7.3 For mechanical-drive steam turbine water-induction prevention, install a moisture separator in the supply piping, and bucket traps to drain any captured condensate from the steam separators. A source of water in mechanical-drive turbines could be from long extraction piping systems that also connect to other LP steam systems or let-down stations.

A. Install a steam moisture separator upstream of the shutoff valve to prevent water from entering the turbine and check for proper operation once per week.

B. Inspect the proper operation of bucket traps that drain condensate from the steam separators once per week.

C. When a steam moisture separator is not installed, a continuous drain must be connected to the lowest point of the steam inlet piping. Turbine drains on the steam chest, turbine casing, and exhaust piping should be opened prior to every startup. Installation of a drain system with automated drains is recommended.

D. Implement a routine annual borescope inspection program to detect the early onset of moisture erosion in the steam path blades and vanes.

E. Develop written startup and shut down procedures that clearly list all drains and how to open them and verify flow.

F. Verify closure of the manual/automatic valve upstream of NRV on the extraction line and backpressure line after turbine shutdowns to prevent egress of steam line condensate into the turbine casing.

G. Dismantle and inspect the drain line valves during planned maintenance outages to ensure proper closure and flow when opened.

H. Inspect the attemperator valves for tightness to prevent inadvertent leakage during every maintenance outage.

I. Install a low temperature alarm and trip for inlet steam low superheat temperature if required by the turbine OEM. Thermocouples may be installed in the turbine, or in the connecting steam piping at locations determined by the turbine manufacturer, to assist in preventing water induction or cold steam from entering the turbine.

2.1.8 Vibration Monitoring System

Provide a vibration monitoring program to assist in the evaluation of a machine’s condition. Include vibration tripping authorization and corrective action steps to follow in plant policies and procedures addressing the handling of vibration issues.

There are two principle methods of monitoring machine vibration: fixed and hand-held. For further information, see Section 2.2.4 of this document.

2.1.9 Steam Turbine Performance Monitoring

2.1.9.1 General

Provide a turbine performance monitoring program to evaluate and assess the thermal performance. The evaluation and assessment of performance data should have the following purpose:

A. Establish baseline performance

B. Detect deterioration in the thermal performance by trending changes in various performance parameters

C. Identify the cause of performance degradation by proper data evaluation and interpretation

D. Facilitate development of cost-effective solutions to correct operational and equipment problems that are contributing to the degradation in thermal performance

2.1.9.2 Critical Parameters

Include the following essential parameters in the performance monitoring program:

A. Obtain baseline performance data on individual turbines and cycle components during initial operation and after a maintenance outage to establish a base for identifying specific areas of performance losses

B. Periodic acquisition of repeatable performance data

C. Proper evaluation and assessment of performance data so deterioration can be detected, located, trended, and corrected in a cost-effective manner

D. Detailed inspection and quantification of the expected performance recovery from restoration of turbine steam path

E. Testing procedures and monitoring activities that are effective for obtaining and evaluating performance data

F. Accurate trending of various performance characteristics, such as the turbine steam path flow, pressure, and temperature, that are reviewed and studied to locate and identify the cause of any turbine deterioration

G. A turbine steam path evaluation to identify the specific components contributing to any loss in thermal performance, including deposits, solid particle erosion, increased clearances in packing, and foreign object damage

2.1.10 Steam Turbine Shaft Seal and Gland Steam Seal Protection

Provide turbine shaft seals or a gland seal steam system where applicable.

2.1.11 Control Systems

2.1.11.1 Ensure the steam turbine controls meet the recommendations in Data Sheet 7-110, *Industrial Control Systems*.

2.2 Operation and Maintenance

Establish and implement a steam turbine inspection, testing, and maintenance program. See Data Sheet 9-0, *Asset Integrity*, for guidance on developing an asset integrity program, including quality assurance/quality control (QA/QC) practices and procedures.

2.2.1 Overspeed Protection System Testing

2.2.1.1 Electronic Overspeed Protection Systems (Generator-Drive Steam Turbines)

2.2.1.1.1 Test the overspeed protection system annually using a functional (fired) or simulated test to verify the system's integrity.

2.2.1.1.2 Perform a functional test of the overspeed trip system, at or below rated overspeed, in conjunction with the following events:

A. During initial commissioning, before first synchronization to the grid

B. After repair, rework, and/or replacement of any components of the overspeed protection system (forced outage, overhaul, or major inspection) before synchronization to the grid

C. After repair, rework, and/or replacement of any components of the electronic overspeed protection system

Note: Performing a functional overspeed test for one of the reasons indicated above satisfies the annual functional testing recommendation.

2.2.1.1.3 Prior to testing the overspeed protection system, stroke test and exercise all steam admission valves (e.g., emergency stop valves, shutoff valves, and governor/control valves), extraction non-return valves, and all associated trip mechanisms according to the OEM's manual to ensure free movement.

2.2.1.1.4 Decrease the turbine load until all the steam supply valves are verified closed, so the Generator circuit breaker (GCB) opens by reverse power. This will ensure that all emergency shut off valves (ESV), non-return valves and the turbine control valves are fully closed. Do not manually open the GCB in any circumstance, because this can lead to an instantaneous overspeed condition if the steam supply valves are not fully closed.

2.2.1.1.5 Ensure the testing procedure includes the recording of completed overspeed trip test results, including a section for comments describing any aborted tests or other test difficulties experienced. Ensure operating personnel have documented proficiency in the procedure and control logic.

2.2.1.1.6 If the test was of the functional type, with the change of trip setpoint, also include in the testing report a field for verification that the trip setpoint was returned to the original value and this value was checked by a second responsible person.

2.2.1.1.7 Perform two tests, with the maximum speeds within the tolerances specified by the manufacturer. If the test is out of tolerance, consider the overspeed test to have failed. Troubleshoot the overspeed system to determine and correct the cause of the failed test. Its recommended to conduct one additional test with the tolerances specified by the OEM's instruction book/manual. Document test results, including any failed test.

2.2.1.2 Mechanical Bolt Overspeed Protection Systems

2.2.1.2.1 Perform all tests in accordance with the OEM's manual for the specific turbine. Fully test the system at least once per year and following turbine overhaul, system repair, or major outage, or replacement of any components of the overspeed protection system, and prior to returning the turbine to normal service.

2.2.1.2.2 Ensure the testing procedure includes the recording of completed overspeed trip test results, including a section for comments describing any aborted tests or other test difficulties experienced. Ensure operating personnel have documented proficiency in the procedure and control logic, and there is adequate communication between operating personnel doing the testing.

2.2.1.2.3 Perform the test at the maximum speeds specified by the manufacturer. If the test is out of tolerance, consider the overspeed test to have failed. Troubleshoot the overspeed system to determine and correct the cause of the failed test. Following that, conduct two additional tests. Document all test results, including failed tests.

2.2.1.3 Mechanical-Drive Steam Turbine Overspeed Prevention (Electronic and Mechanical Bolt Type Overspeed Trip Systems)

2.2.1.3.1 Perform visual and fluorescent penetrant inspection (FPI) nondestructive testing on the turbine and driven object shaft every 5 years.

2.2.1.3.2 Perform visual and ultrasonic test on coupling bolts, couplings, driveshaft and gears every 5 years.

2.2.1.3.3 Inspect drive belts, and drive chains every 5 years.

2.2.1.3.4 Inspect speed governor and surge protection system at every major turbine dismantle inspection.

2.2.2 Lube-Oil System

2.2.2.1 Emergency Lube Oil System Testing

2.2.2.1.1 Test the emergency lube-oil pump (ELOP) in accordance with the OEM's instructions, at the following frequencies:

- Quarterly
- After maintenance of the lube-oil pump system or instrumentation
- After any PLC software change, even if not related to the oil system
- No longer than 18 months if only functional testing is performed. Conduct this testing during a plant outage.

The pressure drop test is the preferred method, which is performed by dropping the oil pressure using a three-way valve and an orifice plate.

If a unit is started at least once every quarter and part of the startup procedure is to conduct a functional test of the emergency lube-oil pump, this is an acceptable alternative to quarterly testing. As part of this test, confirm operability of the pump by checking the outlet pressure, motor amperage, or other means as appropriate. Record and trend the results.

2.2.2.1.2 Perform a functional test and calibrate the pressure switches, pressure transmitters and level sensors in the system in accordance with the OEM's instructions but at least annually.

2.2.2.1.3 If a pressurized or gravity rundown tank is used to supply emergency lube-oil, test the tank low-level alarm at least annually.

2.2.2.1.4 For units that will run continuously for longer than the recommended test intervals, ensure the installation makes provision for the components of the emergency lube oil system to be tested while the unit is in operation.

2.2.2.1.5 If a lube oil cooler temperature control valve is used to control oil temperature, test and calibrate the control valve annually to prevent hot oil from bypassing the lube oil coolers and damaging the bearings.

2.2.2.1.6 Reference Data Sheet 5-28, *DC Battery Systems*, for inspection, testing and maintenance practices.

2.2.2.2 Lube-Oil and Seal-Oil System Condition Monitoring Program

2.2.2.2.1 Establish an effective lube-oil system condition monitoring program that includes written documentation setting forth goals and requirements that reflect the equipment's application, operating history, and the risk. The basic elements of an effective lube-oil management, inspection, testing, and maintenance program include, but are not limited to, the following:

A. Provide purchase specifications with every purchase order for replacement oil.

B. Store replacement oil in properly identified, sealed containers. To prevent contamination, store oil in a clean, controlled environment.

C. Sample the replacement oil prior to use to ensure it is the specified oil and not contaminated.

D. Perform oil reservoir pre-closure inspection and sign-off to prevent debris from entering the oil system following any maintenance work and following refill. Follow OEM recommendations for startup of units as it relates to reservoir cleaning and screen mesh requirements.

E. Perform oil analysis according to the recommendations of the OEM regarding frequencies, point of sampling and reference values for each parameter.

F. Sampling frequency: Start with quarterly analysis. The frequency might be decreased to every six months if good and continuous conditions are observed and trended. Additionally, conduct an analysis prior to outage planning to identify any adverse conditions that can be rectified during the outage.

G. Use a qualified lab, and in accordance with ISO standards, have oil samples analyzed to detect the presence of excess moisture, metallic particles, and contaminants (including varnish if the operating conditions make this a concern). Trend conditions to identify ongoing concerns.

H. Trend all parameters, search for any parameters with a tendency to deviate from the reference values, and plan accordingly to address the situation. Consult with the OEM or a reputable contractor for guidance. Deviations in water content might indicate steam packing glands are worn or that an oil-water heat exchanger is leaking. White metal (babbitt) components might indicate wear at bearings. A high varnish potential indicates varnish is forming in the oil and might cause emergency stop or steam control (governing) valves to seize, stick, or malfunction.

I. If oil is to be recycled onsite during an outage, adhere to the specifications for the conditioner to be used (e.g., oil type, the purity required, and the contaminants that could reasonably be encountered).

J. Ensure the oil sampling points are representative of the oil in the entire system. Have oil samples taken at the bearing oil return lines, or drains. Unless recommended by the OEM, do not collect samples in points downstream of the oil filters and upstream of the bearings because those locations may not identify impurities in the oil tank or at the bearing pedestal oil sumps.

K. For an oil-purification system using a centrifuge, ensure two additional samples are taken every two weeks. These samples are from the inlet and outlet sampling ports on the centrifuge itself. The intent of these samples is to provide a means for determining when the centrifuge needs cleaning and its effectiveness.

L. Reference Data Sheet 5-28, *DC Battery Systems*, for inspection, testing and maintenance practices.

2.2.2.3 Bearing Alignment and Coupling Inspection

At every dismantle, check bearing alignment. To align for steady-state operating conditions using cold alignment methodology, use estimated operating temperatures at the pedestal to correct for temperature differentials. An acceptable alternative is the use of hot alignment at steady-state temperature. Check bearing alignment every two years (or as necessary, based on the historical operation) where a problem exists that requires periodic realignment of the bearings, or because there is a history of shaft fracture, cracking, or coupling distress.

2.2.2.3.1 Examine the coupling at each dismantle. Examine the spline teeth of a gear coupling for evidence of worm tracking and clean the teeth of any sludge build-up. NDE the flanges, spool, bolts, and nuts to establish integrity for rotary gear coupling. For inspection frequency, and more information on couplings and dynamic compressors, refer to Data Sheet 7-95, *Compressors*.

2.2.3 Turbine Water Induction Testing and Inspection

The following testing, inspection, and maintenance recommendations are intended to minimize the risk of turbine water damage and are in general agreement with the intent of the recommendations made in ASME TDP-1-2023.

2.2.3.1 Quarterly Testing and Inspections

2.2.3.1.1 For all the following tests, include complete control loop tests of normal and redundant systems from the initiating signal to the action the indicating signal is intended to perform.

2.2.3.1.2 Test high and high-high boiler drum water-level elements and alarms, including control room indication.

2.2.3.1.3 Test all feedwater heater level controls, elements, alarms, transmitters, and interlocks. Verify the operation of level control instrumentation and check all annunciators to verify alarm indication. Perform the testing in a manner that simulates as closely as possible the actual flooding of a heater without endangering the turbine or other station equipment, and without tripping the unit. Repair or replace tested devices that do not function properly.

2.2.3.1.4 Avoid bypassing of interlocking devices as far as possible. When this is necessary for testing critical water prevention equipment (such as extraction block valves, drain lines, and feedwater heater level controls), verify that the equipment has been restored to the original operating condition.

2.2.3.1.5 Test the mechanical and electrical operation of all steam line drain valves. Where applicable, operate the valves from the control room and determine if the valve is operating properly by observing the ″open″ and ″close″ indicating lights in the control room.

2.2.3.1.6 Inspect all turbine and steam pipe drain lines to ensure the lines are not plugged. Satisfactory inspection techniques include contact pyrometers, infrared thermography, and thermocouples to determine by temperature difference that the line is clear.

2.2.3.1.7 Inspect all traps and orifices in drain lines to determine if they are functioning properly. Satisfactory inspection techniques include contact pyrometers, infrared thermography, and thermocouples

2.2.3.1.8 Where the tests described above indicate inoperative drain lines, at the next planned outage disassemble and internally inspect the flow devices (drain valves, steam traps, or orifices) to verify they will operate properly. Also, inspect or test connecting piping to verify the flow path is clear.

2.2.3.2 Annual Inspections and Maintenance

2.2.3.2.1 Test all valves essential to water induction prevention (such as attemperator spray valves and power-operated block valves) for tight shutoff or perform an internal visual inspection. Also test all associated interlocks and controls.

2.2.3.2.2 Verify that control room indication of steam line drain valve position is working as intended by physically checking the actual valve movement.

2.2.3.2.3 For all steam line drains, clean all drain pots, traps, and orifices.

2.2.3.2.4 Verify functional testing and calibration of all protective devices. Verify and record alarm and trip settings.

2.2.3.3 Three-year Maintenance

2.2.3.3.1 Dismantle and clean level switches on feedwater heaters.

2.2.4 Vibration Monitoring, Testing, and Analysis

2.2.4.1 Vibration monitoring is necessary to assist in the evaluation of a machine’s condition. Include vibration alarming and tripping authorization and corrective steps to follow in plant policies and procedures addressing handling of vibration issues. Vibration signatures are needed to establish a baseline for monitoring and trending equipment performance. Establish new signatures any time an overhaul is performed, and more frequently if adjustments to alignment or balancing are made.

2.2.4.2 Take readings more frequently if trends reflect imminent problems, such as step increases. Take readings at the same location points to ensure consistency of data.

2.2.4.3 If monitoring values differ from the specification/operation parameters, evaluate the trend and investigate. Take corrective action, as necessary. However, if the vibration level exceeds specifications, and operating limits, shut down the turbine and investigate.

2.2.4.4 Calibrate all monitoring equipment at least annually or after every major scheduled outage. A check against a calibrated hand-held portable monitor is satisfactory.

2.2.4.5 Fixed Monitoring

2.2.4.5.1 Visually check the vibration level at each point at least daily, and record weekly, if automatic recording is not done or if a single entry satisfies the weekly summary performance log requirement versus a reference to a strip chart, etc. Compare results and trend data weekly.

2.2.4.5.2 Ensure alarms sound in a constantly attended location. Investigate all sound alarms, verify the cause, and take the necessary corrective action. Record data and findings.

2.2.4.5.3 On units with shaft position indication installed, calibrate the detectors annually, after every major turbine outage, and after any system overhaul.

2.2.4.6 Hand-Held Monitoring

2.2.4.6.1 Where manual(hand-held) intermittent vibration monitoring is used, take readings at each point, record results, and trend data at least weekly. Take readings more frequently if trends reflect imminent problems, such as step increases.

2.2.4.6.2 Take readings at the same location points to ensure consistency of data.

2.2.4.6.3 If monitored values differ from visual checks, evaluate the trend and investigate. Take corrective action, as necessary.

2.2.5 Valve Testing and Dismantle Intervals

2.2.5.1 Generator-Drive and Mechanical-Drive Valve Testing, Maintenance, and Dismantle intervals

2.2.5.1.1 Adhere to the testing intervals listed in Tables 2.2.5.1.1-1 and 2.2.5.1.1-1 and dismantle intervals listed in Tables 2.2.5.1.2-1 and 2.2.5.1.2-2.

Table 2.2.5.1.1-1. Generator-Drive Steam Turbine Valve Testing Intervals

Activity	*Frequency*
Exercise steam admissions valves (all emergency stop valves, intercept, governor valves) to ensure free movement and to remove the residue of steam and other buildup on the valve stems, collars and bushings. See Figure 2.2.5.1.3-1.	Weekly[Note 1]
Exercise extraction non-return valves. See Figure 2.2.5.1.3-2.	Weekly[Note 1]
Test steam admission valves by exercising them the full travel (all emergency stop valves and governor throttle valves).	Annually[Note 1]
Test mechanical operation of all power-assisted check valves, including all solenoid valves, air filters, air supply, air sets, etc.	Annually[Note 1]
Test the boiler or heat recovery steam generator (HRSG) main steam header stop valves for steam leakage	Annually

Note 1. Each time a unit is shut down and started up, this should be documented and counts as exercising the valve, including a full stroke test, as long as no adverse conditions were noted.

Table 2.2.5.1.1-2. Mechanical-Drive Steam Turbine Valve Testing Intervals

Activity	*Small, General- Purpose Steam Turbine Frequency*	*Large, Special- Purpose Steam Turbine Frequency*
Exercise steam admission valves (all emergency stop valves, intercept, governor/control valves) to ensure free movement and to remove the residue of steam and other buildup on the valve stems. See Figure 2.2.5.1.3-1.	Quarterly[Note 1]	Monthly[Note 1]
Exercise extraction non-return valves. See Figure 2.2.5.1.3-2.	Quarterly[Note 1]	Monthly[Note 1]
Test steam admission valves by exercising them the full travel (all emergency stop valves and governor /control, valves). Manual block valves should be exercised by full open and closing.	Annually[Note 1]	Annually[Note 1]
Test mechanical operation of all power-assisted extraction non-return valves, including all solenoid valves, air filters, air supply, air sets, etc. Manual block valves should be exercised by full open and closing.	Annually[Note 1]	Annually[Note 1]
Test the boiler or heat recovery steam generator (HRSG) main steam header stop valves for steam leakage	Annually	Annually

Note 1. Each time a unit is shut down and started up, this should be documented and counts as exercising the valve, including a full stroke test, as long as no adverse conditions were noted.

2.2.5.1.2 Exercise valves equipped with manual handwheels periodically to ensure stems are free to travel. Three or four turns open and closed should verify the stem is not seized and should not cause false trips. However, full functional testing of the valves will provide the same verification. If that is done at scheduled or unscheduled shutdowns/startups and they occur on a quarterly basis, the intent will be accomplished. Document the tests.

Table 2.2.5.1.2-1. Recommended Electric Generation Valve Dismantle Intervals

Activity	*Equivalent Operating Hours-Based Frequency*	*Condition-Based Maintenance Program Frequency*
Dismantle, inspect, and refurbish turbine emergency stop (steam shut-off) valves, governor/control (throttle) valves, and steam extraction line non-return valves.	24,000 EOH	32,000 EOH
Boiler or heat recovery steam generator (HRSG) main steam header stop valves	24,000 EOH	32,000 EOH

For low duty cycle generator drive steam turbines, a valve dismantle outage should not exceed a six year frequency.

Table 2.2.5.1.2-2. Recommended Mechanical-Drive Valve Dismantle Intervals

Activity	*Operating Hours-Based Frequency*	*Condition-Based Maintenance Program Frequency*
Small, general-purpose mechanical-drive steam turbines: Dismantle, inspect, and refurbish turbine emergency stop (steam shut-off) valves, governor/control(throttle) valves, and steam extraction line non-return valves.	16,000	24,000
Large, special-purpose mechanical-drive steam turbines: Dismantle, inspect, and refurbish mechanical-drive turbine emergency stop (steam shut-off) valves, governor/control(throttle) valves, and steam extraction line non-return valves. This applies to all steam turbine types and applications.	24,000	32,000
Boiler or heat recovery steam generator (HRSG) main steam header stop valves	24,000 EOH	32,000 EOH

2.2.5.1.3 Implement the following condition-based maintenance factors of influence to extend the steam turbine valve maintenance interval:

A. Water quality/steam purity is routinely monitored and in line with Table 2.1.6.2.4 without any excursions in the past period. Maintain feedwater and steam purity to turbine OEM limits, as found within this DS, otherwise dismantle valves on an annual basis.

B. No prior operational issues, and no prior distress found during overhaul from review of past inspection reports

C. Control oil or EHC fluid periodic quality testing is documented for moisture, varnish, particulates, and is within guidelines

D. Valves must receive periodic valve testing, to extend the valve maintenance interval

E. A proven valve service life extension upgrade was completed, with features such as: onsite machining restoration of sealing surfaces, improved seals and valve seats, superior corrosion, and erosion resistant alloys, upgraded actuators and instrumentation, protective coatings to prevent wear and corrosion.

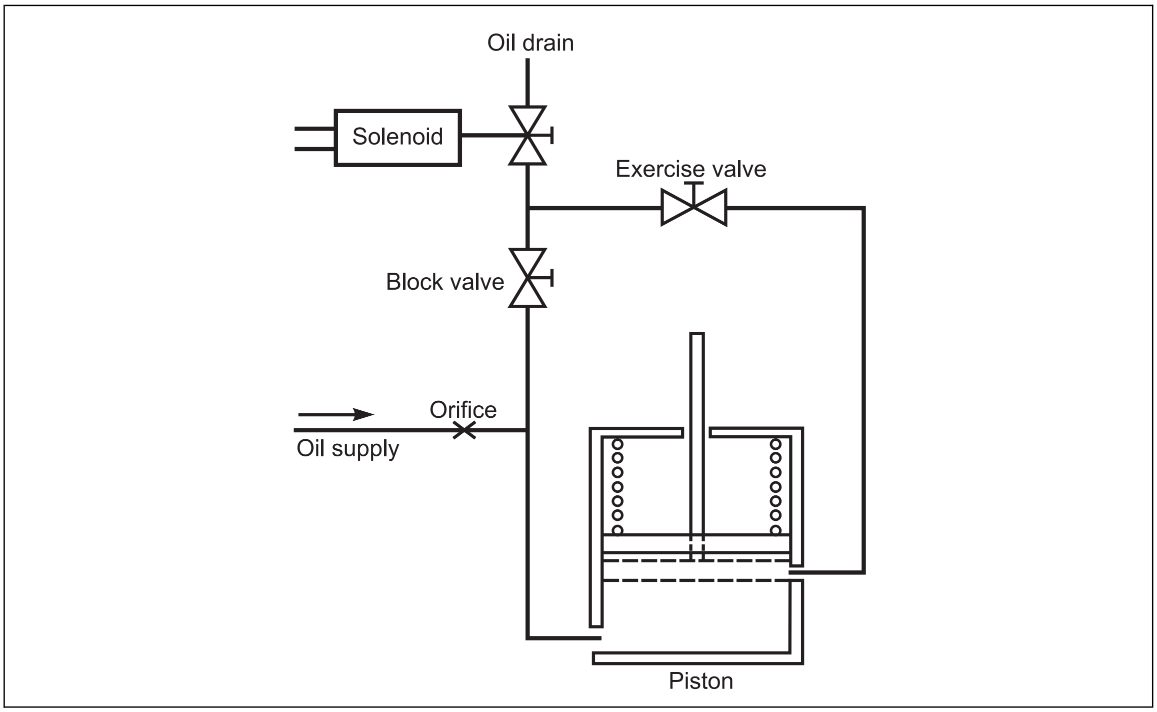

Fig. 2.2.5.1.3-1. Emergency stop valve (ESV) testing schematic

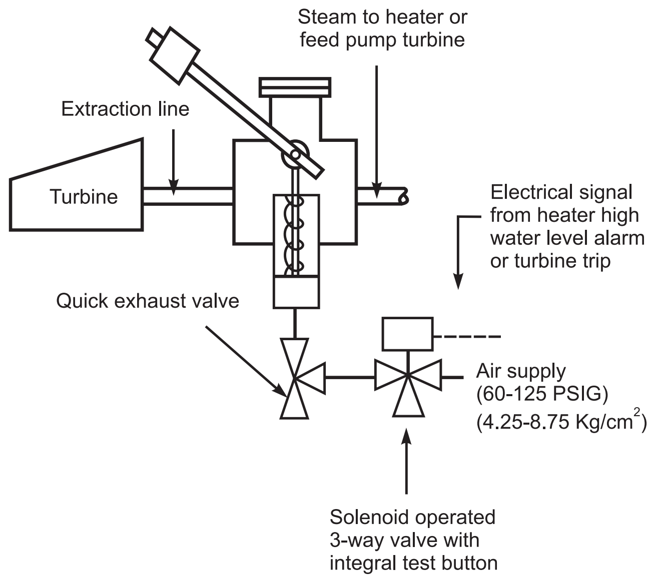

Fig. 2.2.5.1.3-2. Pneumatic power assisted non-return valve (NRV)

2.2.6 Valve Dismantle Inspection

2.2.6.1 Include the following actions in the dismantle inspection:

A. Disassemble valves.

B. Clean valve parts.

C. Measure the clearance between stem (and shaft) and bushing.

D. Perform nondestructive examination (NDE) of stems (or shafts), disks, arms, pilot valves, and seats.

E. Perform total dial-indicated run-out measurement of stems (or shafts).

F. Measure the clearance at valve-guide seal rings.

G. Perform valve seat contact check; perform a blue check or equivalent test of the valve plug to valve seat contact and ensure a band of 100% contact for 360 degrees is achieved on the steam sealing surfaces (valve seat). Lap or grind the valve seat until 100% 360 degree contact is achieved.

H. Replace all fasteners, washers, seals, and similar hardware.

I. Correct all out-of-blueprint measurements.

J. Inspect screens.

K. Perform NDE of bolts and studs (in accordance with OEM recommended replacement intervals).

L. Correct all discrepancies.

2.2.7 Rotor and Casing Dismantle Inspection

2.2.7.1 Implement a robust foreign material exclusion control program during all maintenance and inspection activities. For further guidance on foreign material exclusion, See Data Sheet 9-0, *Asset Integrity*.

2.2.7.2 Include the following actions during a steam turbine rotor and casing dismantle inspection:

A. Lift turbine casings and inspect top and bottom halves (for barrel-type turbines, remove the head flange and internal casing).

B. Remove the rotor(s); clean or grit-blast as necessary, and perform a chemical analysis of any deposits found on the rotors.

C. Inspect the steam chest and nozzle blocks.

D. Remove the nozzle diaphragms; grit-blast if necessary.

E. Perform NDE of nozzle vanes for any indications.

F. Have the OEM's certified engineer or consultant evaluate erosion, corrosion, cracks, dents, nicks on rotor, rotor disks, blades, nozzles, and blades/nozzle airfoil damage and disposition.

G. Perform NDE of disks and rotors. Remove the steam turbine blades and perform NDE of the blades, shrouds, and blade slots/serrations in the rotor disks/wheels, and spindle/rotor. If the blades are not removed from the rotors, a phased array UT inspection may be the only way of getting indications of deep cracks in the blade slots/serrations in the rotor disks/wheels. This inspection is especially important for steam turbines that have experienced any historical steam purity contamination or are in a flexible operating mode.

H. Dismantle, inspect, and check clearances of journal and thrust bearings.

I. Remove and check all control valve components (valve disks, seats, stems, guide, linkages, etc.). Note: Simply exercising the valves does not ensure the valve disk is not broken or warped to the extent that it will not seat securely.

J. Perform NDE of bolts and studs using methods that have a high degree of probability of detection for the intended service. Replace at OEM recommended intervals.

K. Dismantle, inspect, and check operation of emergency stop valves, intercept valves, and non-return valves in extraction lines. Perform NDE of stems, valve disks, and seats. Refurbish as necessary.

L. Perform dismantle inspection and refurbishing of overspeed trip system.

M. Check lube-oil system components.

N. Dismantle and inspect main, auxiliary, and emergency lube-oil pumps; check for proper operation.

O. Check clearances between stationary and moving parts.

P. Inspect steam glands, seals, and packing.

Q. Inspect oil seals.

R. Align bearings.

S. Align couplings.

T. Check turbine shaft alignment. Realign and adjust as necessary to meet the specification using the OEM manual.

U. Perform overspeed test after reassembly.

2.2.8 Dismantle Intervals

Steam turbines are found in multiple occupancies and applications. They are used to drive pumps, fans, compressors, blowers, paper machines, grinders, generators and many other components. There are significant variations in turbine design, application, complexity, supplied steam quality, sizing, etc., but turbines are fundamentally the same. Performance functions, components along with support systems all have similar failure mechanisms as do steam turbines.

2.2.8.1 Establish maintenance and overhaul practices and intervals for steam turbines based on turbine design/construction, application, size, etc., as well as other parameters focused on the highest risk areas of the turbine. There are no regulatory controls as with pressure equipment, so frequencies and tasks vary. In general, the tasks and their frequencies are defined by:

- Original equipment manufacturers (OEMs)
- Consultants
- Industry technical organizations
- Plant staff

- Manufacture product/process
- Insurance providers

For low duty cycle generator drive steam turbines, a turbine dismantle outage should not exceed a twelve-year frequency.

2.2.8.2 Steam Turbine Maximum Dismantle Intervals

2.2.8.2.1 Generator-Drive Steam Turbines

A. For steam turbines operating in base load, load following (within OEM guidelines), or a flexible operating mode (peaking, rapid load following, low load turndown), apply an OEM equivalent operating hour (EOH) -based dismantle interval. For HP, IP, and LP steam turbines, use the OEM published interval or, where no published interval is available, up to 56,000 EOH.

For low duty cycle generator drive steam turbines, a turbine dismantle outage should not exceed a twelve-year frequency.

B. The following conditions will reduce maintenance intervals for all steam turbines below the aforementioned intervals:

1. Operating in OEM avoidance zones such as high condenser back pressure or if a low-pressure turbine vacuum diaphragm rupture occurred during the previous operating period
2. Extended low load turndown below OEM limits
3. Frequent or rapid load cycling beyond OEM limits
4. Steam purity and quality excursions beyond FM guidelines
5. Any water induction event
6. A sudden step change and or phase angle shift in rotor vibration levels that cannot be accounted for

2.2.8.2.2 Mechanical-Drive Steam Turbines

A. Time-based: As recommended by OEMs. If no OEM recommendation is provided, adhere to the following:

1. For general-purpose mechanical-drive steam turbines, complete a major dismantle inspection on a three-year or 24,000 operating hour interval.
2. For special-purpose mechanical-drive steam turbines, complete a major dismantle inspection on a five-year or 40,000 operating hour interval.

2.2.8.2.3 Older steam turbines typically manufactured prior to the 1970s did not use a vacuum-melting process in the manufacturing of the rotor, and the vacuum-melting of rotor forgings (ingots) was not common practice. Despite being forged, the lack of vacuum melting allowed a greater likelihood of discontinuities forming in the metallurgy as it cooled. Ultrasonic examination testing and boresonic inspection of the rotor and rotor bore can determine if cracking exists or is developing and to what extent.

Conduct the following inspections on all rotors manufactured prior to 1970:

A. Perform dismantle and boresonic inspections to check for possible crack development and progression in accordance with OEM recommendations and operating criteria.

B. Evaluate the boresonic results, any other metallurgical testing that was done, and OEM requirements.

C. Have the rotor counter-bored to remove discontinuities found as a result of the boresonic inspection.

D. Map any remaining indications for further analysis and conduct another boresonic inspection within two years to see if the discontinuities have grown.

2.2.9 Condition-Based Monitoring

Condition-based monitoring systems and programs monitor the condition of equipment continuously and intervene when necessary, giving immediate warning of abnormal operation. The approach is to detect turbine component deficiencies as they occur, preventing the conditions that might lead to problems, failure, and/or damage. Include the following in a condition-based monitoring system:

A. Water treatment and steam-purity analysis results recorded and past/current evaluations completed

B. Vibration monitoring

C. Lube-oil monitoring and periodic analysis

D. Performance monitoring of critical parameters

E. Speed control monitoring/documented overspeed test program for overspeed protection system

F. Evaluation of critical components using NDE methods with a good probability of flaw detection

G. Where feasible, phase array/ultrasonic or fluorescent dye penetrant examination on the blade roots, blade carriers, low pressure turbine blades (every three years); borescopic/visual examinations, if practical/possible, every year

H. Annual visual inspection of last two stages of low-pressure turbine blades

I. A record of hours of operation, numbers of starts and ramp rates

J. Evaluation of the turbine's operational condition, data analysis, base-load, peaking, and frequent cycling units

K. Regular inspections that include nondestructive examination (NDE), and visual inspection of any accessible blade surfaces that reveal no indications of cracking or other deterioration

L. Previous dismantle findings recorded and evaluated, with particular attention paid to information related to steam turbine rotors, blades, and internal rotating parts

M. Unit performance evaluated and recorded. Depending on the findings, results of performance monitoring and degree of any material deterioration revealed during visual inspections, decisions on current and future intervals will be affected.

N. Rotor baseline and current condition are determined, defined, and recorded; assessment and evaluation of turbine rotor and critical components are performed based on criteria specified by the OEM.

O. If monitored conditions indicate that dismantle of a given turbine section casing is advisable, only that cylinder need be opened unless, after opening, it becomes evident that downstream damage may have occurred.

2.2.10 Steam Turbine Operation

The following recommendations for steam turbine operation are intended to reduce the risk of turbine failure and rotor damage; adhere to them in the operation of the unit as practical.

2.2.10.1 Operate the turbine in its intended service and in accordance with the manufacturer's recommendations. An example of intended service is a turbine that is initially designed specifically for base-load operation. If this turbine is to be operated in cycling service, have the manufacturer evaluate the machine to ensure it is suitable for the change in service.

2.2.10.2 Adhere to starting, loading, unloading, turndown, minimum/low load requirements, etc. per OEM guidelines and maintain records of any deviations. Ensure operating hours, number of starts, and ramp rates are properly recorded.

2.2.10.3 If shutdown occurs, cool down the machine on turning gear. Keep the turning gear running and the turbine rotating with vacuum until the unit is sufficiently cooled.

2.2.10.4 Ensure all turbine casing drains, steam piping drains, and steam drain pot isolation valves (motorized and manual valves) are opened at startup and shutdown to ensure all condensate is removed from the steam lines and casing drains. This will also prevent pipe hammer.

2.2.10.5 When stopping the turbine, ensure that breaking condenser vacuum earlier than the OEM recommendation is not utilized to reduce rolldown time, in order to prevent low-pressure blade flutter induced cracking.

The operating procedure, the turbine startup and shutdown guidelines, and practices set by the manufacturer have to be followed to ensure that no condensate will flow into the turbine.

2.2.11 Change in Operating Profile

As market demand changes, modes outside of base load operation become more common (i.e., flexible operation). These profiles include terms such as cycling, peaking, intermediate and two-shifting. Consider aspects such as additional unit starts, low or partial load, fast start/shutdown, ramp rate, load following operation and extended layup. These variations in operational profiles could have a profound impact on equipment and components from operating outside of nominal design limits to how the unit is operated, environmental conditions, fuel type/quality, and unit design (heavy duty vs. smaller units). Units may become more susceptible to damage mechanisms that can shorten their service life.

2.2.11.1 For units with a changing operating profile, have an engineering assessment performed by the OEM or alternative service provider (Refer to Data Sheet 9-0, *Asset Integrity*) if a unit is operating outside its design criteria and/or profile (i.e., integrity operating window). Apply a Management of Change process to include aspects such as plant operation and procedures, starts/trips, inspection intervals, testing, maintenance schedule, operating conditions. Include an evaluation of current and new failure mechanisms, and how the unit will be impacted with age, hours, and cycles. Increased frequency of outages or overhauls will be necessary if identified areas of concern cannot be adequately inspected. The installation of additional functioning supervisory instrumentation may also be required, if areas of concern cannot be adequately inspected.

The following should be considered for steam turbines operating with a flexible profile:

A. Update written startup and shutdown procedures to include specific guidance for flexible operations within OEM guidance for heat soak hold points to preclude undue thermal stress. The steam turbine and boiler startup profiles should be in coordination to reduce thermal stress. Maintain good operating records to allow for accurate estimates of component damage, including thermal fatigue and creep damage.

B. Record Starts/stops/trips for required maintenance of inherent components capable of experiencing increased wear (e.g. stop valves, control valves, etc.). If maintenance is deferred and a previous overhaul report identifies prior open repair recommendations, a borescope inspection is required to ensure safe operation. If the turbine is not equipped with borescope openings, it is recommended to retrofit the turbine to install borescope openings (plugs) where a visual inspection of the steam path and deposit sample analysis can be performed annually.

C. Provide on-line monitoring of water and steam purity per OEM and FM guidelines.

D. Conduct airfoil damage assessments due to phase transition zone movement.

E. Evaluate turndown guidance, minimum/low load requirements, and any associated periodic inspections that may confirm reliability of components. This may include:

1. Visual or other NDE methods of various components affected by low load operation, in particular the latter stage blading of the low-pressure turbine (e.g., L-0 blades, L-1 blades, L-2 blades etc.).
2. Determine if the OEM has published any avoidance zones that establish exclusion zones of operation (minimum load, exhaust temperature, condenser low vacuum/high back pressure) to eliminate the potential for unexpected low-pressure turbine blade vibration and distress.
3. Determine if the mechanical-drive steam turbine OEM has published any guidance on rotor critical speed avoidance zones, and, if so, develop operating procedures to mitigate this risk.
4. If any LP steam turbine has operated in a low load back pressure “Avoidance Zone” as published by the OEM, or experiences a blown overpressure rupture diaphragm and lost vacuum, then the low pressure turbine last stage blades must be visually and NDE inspected at the next opportunity for blade fatigue cracking.
5. Assess the potential for low-pressure turbine blade vibration and the need for monitoring techniques. Monitoring of these stages should be considered via blade vibration monitoring or tip timing technologies if operating beyond the as-designed basis, especially for certain types of blade designs.
6. Minimize the operation with water sprays for units operating at prolonged periods of low-load operation. Employ a temperature-dependent proportional water spray system. Exhaust hood spray isolation valves should be tested for leaks to prevent inadvertent water droplet introduction during operation.

7. Ensure the unit operates according to OEM recommended axial differential expansion limits. If the unit is operated per the OEM recommendations with respect to loading rates and operating temperatures, then cold starts, operation down to low load, ramping up and down, and load swings will not result in an axial differential expansion type events. Any time inlet temperature is changing with load, differential expansion should be carefully monitored in order to prevent axial type rubs. Equip units expected to operate in a cycling mode with functioning supervisory instrumentation located at critical axial locations to monitor the differential expansion. Supply a high alarm that warns operators to adjust their actions, and a high-high alarm to warn of impending axial rubbing damage. Monitor differential expansion data and take corrective action when a high alarm is indicated. During maintenance outages, any axial rub patterns should be noted and correlated with recent operational upsets.

F. Update procedures related to shutting the unit down, intermittent offline periods, and layup. Follow OEM and FM guidance on best practices for frequent and/or extended equipment layups. Of primary concern is steam turbine upper and lower casing differential thermal expansion, rotor bow concerns, and rotating component interference on turning gear.

1. Identify the methods by which major pieces of equipment are being preserved and protected when idle. The duration of the layup should factor grid or load demand needs, as well as periods of uncertainty to maintain the reliability of key equipment and associated process components.
2. An assessment by the OEM and/or qualified alternative service provider is recommended to evaluate which layup strategy is appropriate for each individual unit and auxiliary equipment. This may include:
   - Wet layup
   - Wet layup with a nitrogen blanket
   - Dry layup with dehumidified air or nitrogen blanket
   - Drained
   - Shutdown as-is
   - Keep in service
   - Maintain Circulation
   - Surface barriers
   - Stored

Reference Data Sheet 7-109, *Fuel Fired Thermal Electric Power Generation Facilities*, for recommended equipment layup procedures.

G. Inspect for casing, diaphragm, and nozzle cracks or deformation due to thermal and cyclic stresses. Water ingress, droplet formation, and wet steam are known to initiate stresses that can lead to deleterious conditions and adversely affect component integrity.

H. Validate upgraded and/or non-OEM components. Due diligence to properly vet the manufacturer, design, validation, and intended operation is appropriate when installing components on units with a flexible operation profile. Materials or designs may lead to unintended consequences if not properly managed.

I. Update valve inspections and maintenance frequency. Given the varying steam loading requirements, thermal fatigue (due to cyclic load), solid particle erosion (due to low or part load operations), blue blushing (due to high steam inlet temperature) may impact normal operation and/or fail to operate in some instances causing the unit to overspeed when disconnected from the load. Assessments should be made to determine any change in frequencies to overhaul these components.

K. Units in flexible operation will experience more frequent turning gear use and increased wear. Turning gear failure could lead to extended down time due to rotor bowing and the long lead time for replacement parts. Adopt a condition-based, preventative maintenance approach, which includes an internal visual inspection at each scheduled turbine outage. Perform a daily external inspection for oil leaks, vibration or unusual noises. Develop a contingency plan and adequate sparing to reduce downtime based on the specific turning gear design. Reference FM Data Sheet 9-0, *Asset Integrity*, for contingency plans and sparing.

2.2.12 Operators

2.2.12.1 Refer to Data Sheet 10-8, *Operators*, for guidance on operator training programs, the competence of operators in their day-to-day roles, the supporting management structure, and organizational culture.

2.2.12.2 Ensure operators are trained to identify operational deviations that may lead to equipment damage, such as steam quality/purity excursions or water induction events.

2.2.12.3 Ensure there are procedures in place to evaluate the effects of these operational excursions on the safety of operating the equipment, which may involve the authorization to take corrective action up to and including taking the unit offline.

2.2.12.4 Due to operational profiles changing, adequate refresher training and material should be made available to refamiliarize operating crews with methods of identifying trends of an off-normal state, as well as preparatory guidance to emergency conditions based on these profiles.

2.2.13 Contingency Planning

2.2.13.1 Equipment Contingency Planning

When a steam turbine 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 steam turbine 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 steam turbines:

A. OEM design information for the steam turbine

B. Processes and procedures needed for removal, dismantling, transportation, availability, and installation of a steam turbine and/or components

C. Review of any service agreements with the OEM and/or vendors to identify the duration of delivery of the steam turbine and/or components. Review steam turbine repair/replacement options/sources strategy, focusing on rotors, blading and stationary elements.

D. OEM and/or third-party vendor review to determine the optimum spare part strategy. For mechanical-drive steam turbines in critical service, evaluate equipment breakdown sparing as a mitigation strategy for the equipment contingency plan. This sparing can include critical valve(s), bearings, bladed rotor, and stationary diaphragm components.

E. For service aged units, consult with the OEM to determine the rotor service life and remaining useful life. Based on the results, develop an equipment contingency plan to prepare in advance the response to a premature failure of the rotor in service, addressing any gaps between the remaining useful life timeframe and the repair, refurbishment, or replacement timeframe.

2.2.13.2 Sparing

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

2.3 Equipment **Alerts**

Original equipment manufacturers and alternative service providers issue technical bulletins or alerts when design or operating problem 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 steam turbine integrity and reliability. Urgency and implementation are designated by the timing and compliance codes within the bulletin/alert.

3.0 SUPPORT FOR RECOMMENDATIONS

Steam turbine generators are the backbone of industry when it comes to energy supply and production. The turbine's efficiency and availability are two important factors. Outages and unexpected shutdowns represent serious losses, with a corresponding increase in generation cost. Therefore, preventive maintenance programs, inspection services, good operating practice, satisfactory control, and continuous monitoring systems are essential to power generation production and availability. They are important measures in maintaining safe, secure, and optimum operation.

Modern supervisory devices and special checks can be used to reveal trends toward serious operating situations with such clarity and speed that overhauls can be carried out when the defects in the machine first occur, rather than to a fixed time schedule, when more damage may have been done.

There should be no dispute over the continued necessity and value of overhauling steam turbines. Failure to carry out preventive maintenance and planned major outages/overhauls as recommended in the user manual supplied by the original equipment manufacturer (OEM) can have serious consequences, leading to costs and downtime substantially greater than would have been caused by the planned outage and maintenance.

The purpose and logic behind turbine overhauls is a comprehensive analysis of the condition of the turbines and auxiliary equipment, in addition to the usual operation supervision and special measurements. Certain things, such as early signs of cracking in highly stressed components, can normally only be detected by testing during a major overhaul, when all parts of the machine have been dismantled. In addition, overhaul provides a way to accomplish the following:

A. Rectify any defects that may have occurred

B. Detect any incipient damage or causes of malfunction and rectify them or assess them and monitor their further progress

C. Analyze the condition of the turbine

D. Obtain data in order to estimate the remaining useful life of the turbine

E. Improve efficiency by removing deposits and replacing worn parts

3.1 Lubrication System

The recommended turbine lubrication system is designed to provide an ample supply of filtered lubricant at the proper flow, pressure, temperature, and viscosity for the operation of the turbine and associated equipment. The recommended system, with all its components, devices, and controls can provide satisfactory online and offline monitoring, and safe operation for the turbine. It can monitor the machine and alert the operator through the control system by sending the alarm signal prior to tripping the unit, preventing forced shutdowns, tripping, failure, and losses.

Lube-oil analysis is essential to the correct operation of the turbine bearings and connected pieces of equipment such as gear boxes and mechanical-drive equipment. Oil analysis can indicate adverse conditions such as wear in the bearings, steam or oil packings, labyrinth seals, and seal rings. It can identify the presence of water, contaminants, varnish, and the general ageing of the oil (loss of additives).

A. Mechanical-Drive Steam Turbine Lubrication

Depending on rating and application, mechanical-drive steam turbines may use ring oil lubrication, saddle pump/steam turbine shaft driven, or force-feed pressurized pump systems.

1. Ring oil lubrication carries oil from the sump to the turbine bearings, by oil rings affixed to the turbine shaft rotating in the oil bath inside the bearing housing. Typically, one oil ring is used per bearing, providing lubrication during startup, normal operation, and coasting down. The oil level in the sump is critical to proper operation.

2. Saddle pump/steam turbine shaft driven lubrication provides lubrication during startup, normal operation, and a DC lube oil pump for emergency shutdown and turning gear operation.. This type is typically used on small, single-stage turbines where oil temperatures exceed 180°F or 82°C. The saddle pump is usually mounted on the coupling end bearing cap and is shaft-driven through spur gears or is shaft-driven direct-drive or driven through a gear reducer or increaser. The system pressure is typically

3 to 5 psig. If the main oil pump is shaft-driven, oil rings or an auxiliary oil pump are used during startup and run-down.

3. In force-feed pressurized systems an oil pump sends pressurized oil directly to the turbine bearings. This type is used when operating speed, power, or temperature exceed the practical limits of ring oil or saddle pump/shaft driven systems. Pressurized oil is circulated throughout the lube oil systems that may contain main, auxiliary, and emergency oil pumps. The most common types are positive displacement gear and centrifugal oil pumps.

3.1.1 Bearings and Lubrication

Journal and thrust bearings support the weight of the rotor. During operation they resist radial and axial loads and maintain stability of the lubrication

A typical tilting-pad journal bearing consists of a housing split along the centerline with tilting pads fitted under the rim of each shoe (see Figure 3.1.1-1). The tilting pads are fitted with temperature-detecting devices to monitor bearing metal temperatures (see Figures 3.1.1-2 and 3.1.1-3).

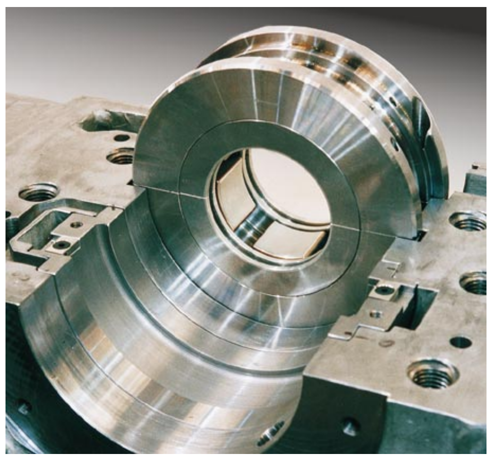

Fig. 3.1.1-1. Tilting pads-type bearing
(General Electric Company, all rights reserved, used with permission)

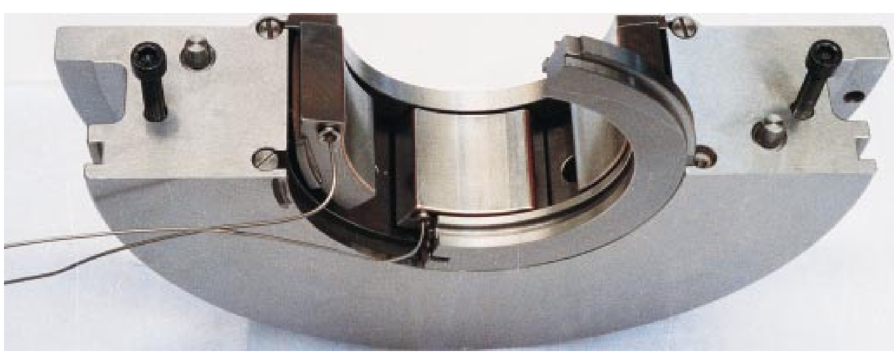

Fig. 3.1.1-2. Typical tilting-pad journal bearing with temperature detective devices
(General Electric Company, all rights reserved, used with permission)

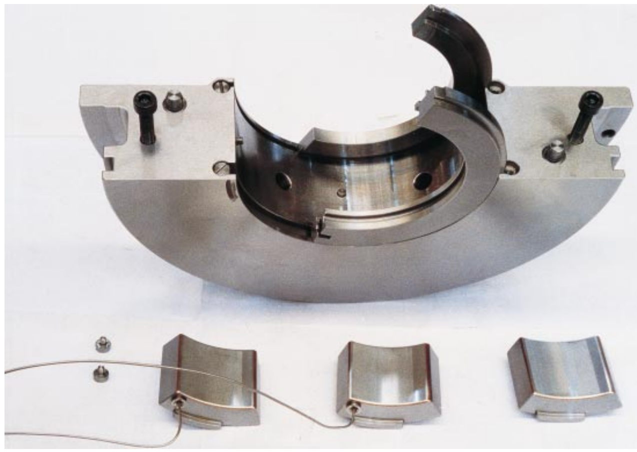

Fig. 3.1.1-3. Journal bearing pads with secure pins (General Electric Company, all rights reserved, used with permission)

Bearing lubrication systems need to be thoroughly cleaned of all debris, moisture, metallic particles, and corrosion.

Evidence of metallic particles in the oil analysis indicate potential damage to the bearing Babbitt liner materials, which will result in bearing failure. Also, the presence of water in the oil exceeding the specified allowable limit indicates a problem with the steam seal system, which will cause failure of the bearing knife edge steam seals. It could also be an indication of tube leakage through the oil coolers (heat exchangers). The presence of excessive contamination in the form of particulates could scratch or score bearing surfaces. When scratching and scoring become widespread on bearing surfaces, the oil film may break down, permitting contact between the stationary and rotating members, wiping the journal and the bearing.

Incipient wiping of a bearing may sometimes be detected by monitoring the temperature of the oil on the discharge side of the bearing. Thermometers and/or thermocouples are installed in bearing cap wells or in drain lines for this purpose. The discharge temperature is based on the oil cooler outlet temperature plus a bearing temperature rise. Use manufacturer's recommendations for these various values. An abrupt increase in bearing temperature may indicate that wiping is taking place.

Thrust bearing wiping, other than that due to lubrication system failures and water induction, is caused by phenomena that transfer pressure drop from stationary diaphragms to the rotor.

Such a transfer may result from accumulation of deposits on rotating blades or stationary vanes, severe distortion of stationary vanes, and/or deterioration of inter-stage labyrinth seals or packing. These phenomena usually lead to measurable drops in performance. In the case of the first two, both efficiency and flow capacity of the turbine are affected, while packing deterioration reduces efficiency only, with no effect on steam flow capacity. Thus, performance monitoring is an effective method of anticipating thrust bearing failures from internal causes. Depending on the thrust-balancing arrangements, high exhaust (condenser) pressure also can lead to thrust bearing wiping. Protection against thrust bearing wiping can be provided by thrust-wear detecting devices or temperature sensing devices embedded in the Babbitt of the thrust pads.

3.1.2 Mechanical System Resiliency

To illustrate the concept of mechanical system resiliency, refer to the system in Figure 3.1.2. In Option A the discharge of the DC emergency lube oil pump ties into the system after all of the system auxiliaries and with no intervening devices between the pump discharge and the bearings to be lubricated. Consequently, the flow from the emergency DC pump can flow directly to the bearings thus minimizing the risk of a lube oil loss.

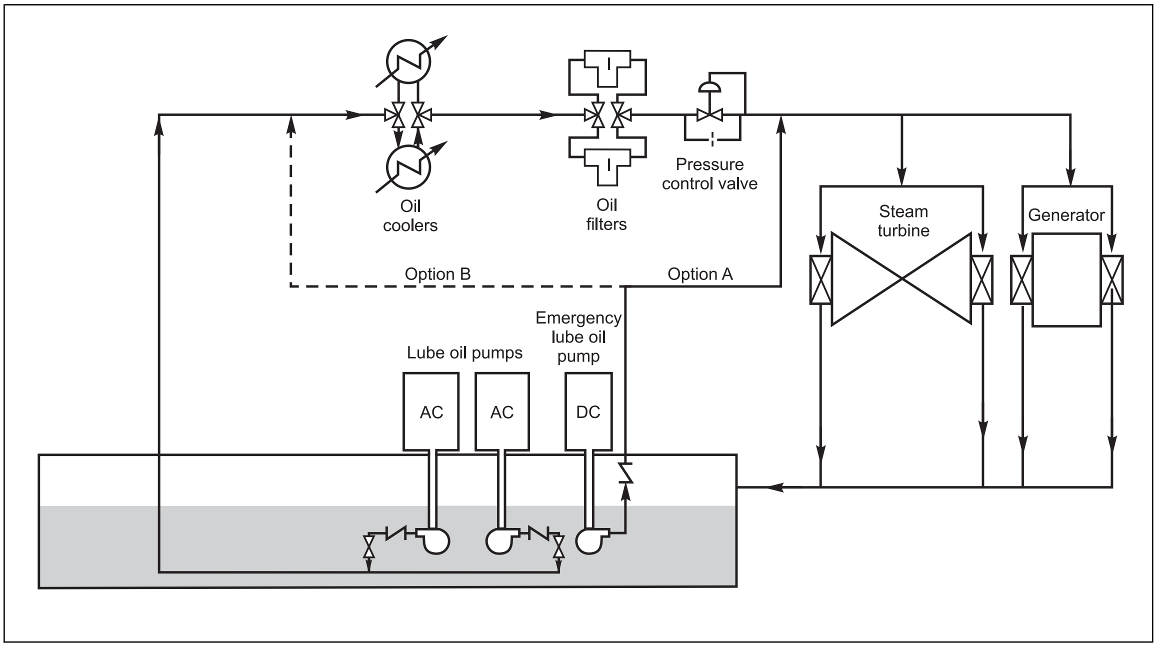

Fig. 3.1.2. Simplified lube-oil system for a steam turbine with hydrodynamic bearings

In the system configuration shown as Option B, the discharge of the DC emergency lube oil pump ties into the system before the oil coolers, oil filters and the pressure control valves. These intervening devices increase the risk of a failure should one of the filter or cooler transfer valves fails and block flow or if the pressure control valve were to fail closed and block flow. In essence, this reduces the resiliency of the system. This risk can be mitigated by doing the following:

A. Altering the configuration of the discharge pipework from the DC emergency lube oil pump so the discharge from the DC emergency lube oil pump feeds directly to the turbine-generator bearings (Option A in Figure 3.1.2). This oil feed line should be unimpeded and without valves.

B. If altering the systems is not an option, do not attempt to changeover the filters or the cooler when the unit is online.

3.1.3 Electrical System Resiliency

Insufficient electrical system resiliency has led to multiple lube oil system failures that consequently led to significant mechanical damage. Predominantly, single DC bus systems designed to provide power for the unit digital control system, protection, and the emergency lube oil DC pump led to multiple losses in the industry.

When a single DC bus system is designed to provide power for the entire DC load, there is a potential for a unit trip and loss of electric power to the emergency lube oil pump when DC power is lost. If the AC pump(s) require DC power to either stay in operation or start up on low oil pressure, the resulting damage from lube oil starvation can be significant.

Independent DC systems for the emergency lube/seal oil system and for the control/ protection systems allow for a more resilient lube oil system.When a single DC bus system is designed to provide power for the entire DC load, the reliability of the AC lube oil pump should be ensured. This can be achieved by using fail-safe designs. In some designs fail-safe AC pumps are achieved by using the scheme of de-energizing in motor control circuit (MCC) to start the motor. This means normally energized (closed) coil of the relay in the control logic when the motor starter is in ″auto position. To start the motor or to maintain the motor in running status, the relay coil is de-energized (open). It is also referred as “drop-out-to-run” design. By this method, the risk of failure to start the motor when required can be reduced.The intent of the recommendations in Section 2.2.2 is to ensure maximum reliability (resiliency) of the lube oil supply to turbine-generators, compressors, etc.

When a steam turbine trips and all steam supply is cut off, coast-down time (run-down time) is the time it takes for the rotor to coast down from its rated operating speed to a stop or turning gear speed (~6 RPM).

For condensing steam turbines, the DC batteries should power the DC circuits for more than 2 hours so the steam turbine can coast down under vacuum. Breaking vacuum too early can cause undue stress and damage to the low-pressure steam turbine blades, especially the last stage L-0 blades. After the steam turbine reaches turning gear speed, it would be ideal if the unit could cool down on turning gear for an additional 30 minutes.

3.2 Overspeed Protection Systems

For generator-drive steam turbines, every trip or shutdown of the steam turbine commands steam emergency stop valve and extraction or bleed steam non-return valve closure to isolate steam flow into the turbine. Failure of the rotor speed to decrease or if the generator continues producing power after a trip suggests an abnormal operating condition. This can be caused by a false trip (see Appendix A for definition). In this situation, proper operator action is essential to prevent a turbine overspeed event.

Opening the generator breaker without isolation of all steam energy sources can lead to overspeed, and catastrophic equipment damage. Every trip or shutdown of the steam turbine must include complete steam valve closure to isolate steam flow into the turbine. In rare circumstances, plants have experienced multi-point failures in the steam system that allowed continued flow of steam through one or more sections of the steam turbine after a trip or shutdown command. In this circumstance the turbine's generator continues to create electrical power. It is critical to keep the generator breaker closed until all steam sources can be isolated or depressurized. Isolation of steam in these circumstances must be done based on plant-specific steam system configuration (closure of manual steam isolation valves, boiler isolation or shutdown, etc.). Failure to confirm steam isolation to the turbine prior to opening the generator breaker may result in destructive overspeed of the steam turbine.

In a false trip scenario, the emergency stop valve could be leaking steam and closed-end limit switches, or linear variable differential transducers (LVDTs) may falsely indicate valve closure and steam is isolated. It may be necessary to close the manual steam stop valve to isolate the steam. It should be verified that extraction/bleed steam lines upstream of non-return valves and the inlet steam line are depressurized. Reverse power flow into the generator should be ensured prior to opening the GCB.

A. Overspeed can occur when one of the following takes place:

1. For turbines that drive generators, one of the initiating events is the opening of the GCB. The instantaneous removal of the generator load can result in an overspeed event.

2. A driven object loses load, either accidentally or by operator error.

3. A sudden change (swing, fluctuation, load rejection with the opening of the GCB or sudden reduction) takes place in the generator load parameters.

4. A coupling failure occurs. This type of event could be associated with a turbine-driven generator or other rotating machine.)

5. Reverse flow occurs through extraction or bleed steam lines.

6. Mechanical-drive steam turbines can experience an overspeed event due to failure of the drive coupling, drive shaft, drive belt, drive chain, gear box, speed governor, a compressor surge/stall event or instantaneous loss of the driven load like a catastrophic failure of the discharge piping in proximity of the driven equipment.

7. Some special purpose steam turbines driving compressors have protection system where the compressor isolates and depressurizes on seal oil leaks. It is important that before these systems are activated manually or automatically, the compressor has tripped, and emergency stop valves and non-returns valves are proven to have closed. This system should also be verified as part of the safety system checks.

8. Reverse rotation is one of the hazards related to turbines driving high pressure mechanical drives. Mechanical-drive turbines are prone to reverse rotation, if compressors/pumps have high pressure and heads and compressor discharge side non return valves fail open. A reverse rotation event can, for example, damage bearings, gearboxes, couplings, and the steam path blades and vanes.

B. Overspeed also can occur during startup prior to load application. When an overspeed event occurs, the turbine speed increases rapidly; if not restrained, one or more of the following may occur:

1. A turbine disk or spindle fracture due to overstress.
2. The generator retaining rings become loose or fracture due to overstress.
3. Turbine blade attachments deform or fracture, releasing blades or allowing them to become loose.
4. A turbine shrunk-on disk stretches to the point of being loose on a shaft.
5. A turbine wheel stretches to the point of severe blade rub.
6. Very severe vibration occurs due to imbalance.
7. A shaft fractures due to overload arising from the excessive speed of the rotor. Shaft fracture is not a primary effect of overspeed, and a fractured shaft between the steam turbine and the generator may be the cause of the overspeed. In such cases, the fracture surfaces usually exhibit evidence of fatigue.
8. Severe bearing damage is caused by rotor whip/whirl.

C. A well-designed overspeed protection system is intended to continuously monitor the turbine speed and offers the following lines of defense during operation:

1. A first line of overspeed defense is provided by the normal speed-control system. When this system detects an increase in the machine's speed, it will close the governor control valves on a proportional basis in response to the speed increase and load rejection, preventing turbine overspeed (see Figure 3.2-1). Note governor/control (throttle) valves can reduce steam flow and rotor speed but should not be relied upon as 100% closure valves.
2. A second line of overspeed defense is provided by the normal speed-control system (PLC software or a dedicated speed control hardware) which will trip the turbine at the overspeed trip set point if an abnormal condition arises in which the normal speed-control first line of defense cannot control the turbine overspeed (see Figure 3.2-2).
3. A third line of overspeed defense is a dedicated emergency overspeed trip system (dedicated hardware), which trips the turbine if an abnormal condition arises in which normal speed control cannot constrain the turbine speed (first line of defense) or trip the turbine before overspeed (second line of defense) (see Figure 3.2-2).
4. It is important to emphasize that the second and third lines of defense actuate over the same final component, the turbine Emergency Stop Valves (ESV), therefore it is essential that these valves are frequently tested for 100% steam sealing (tightness or leakage test) and for freedom of movement and are adequately maintained.
5. As noted in Figures 3.2-1 and 3.2-2 below first line and second line of defense can share speed pick-ups sensors, but third line of defense should have its own dedicated and independent speed pick-ups that are not shared with speed control.

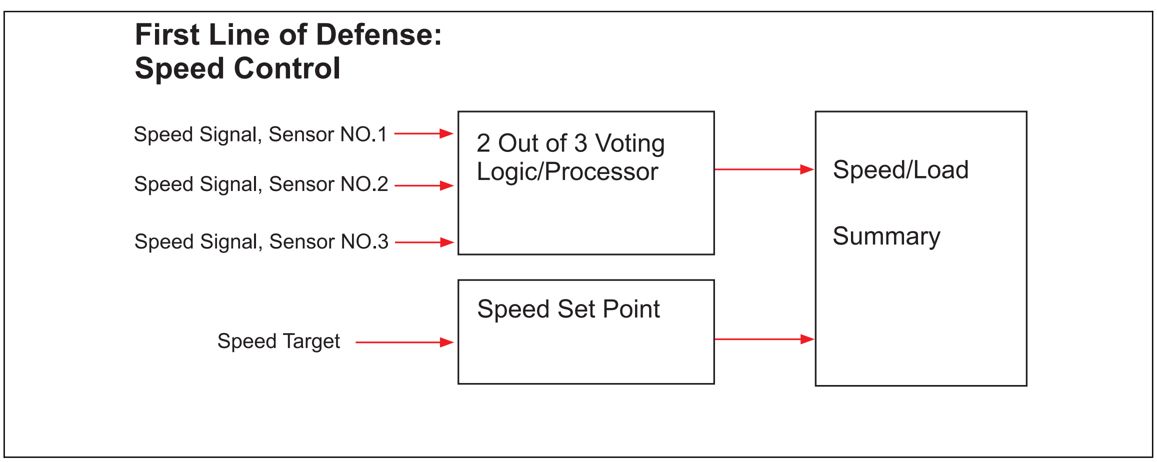

Fig. 3.2-1. Electronic speed sensing system

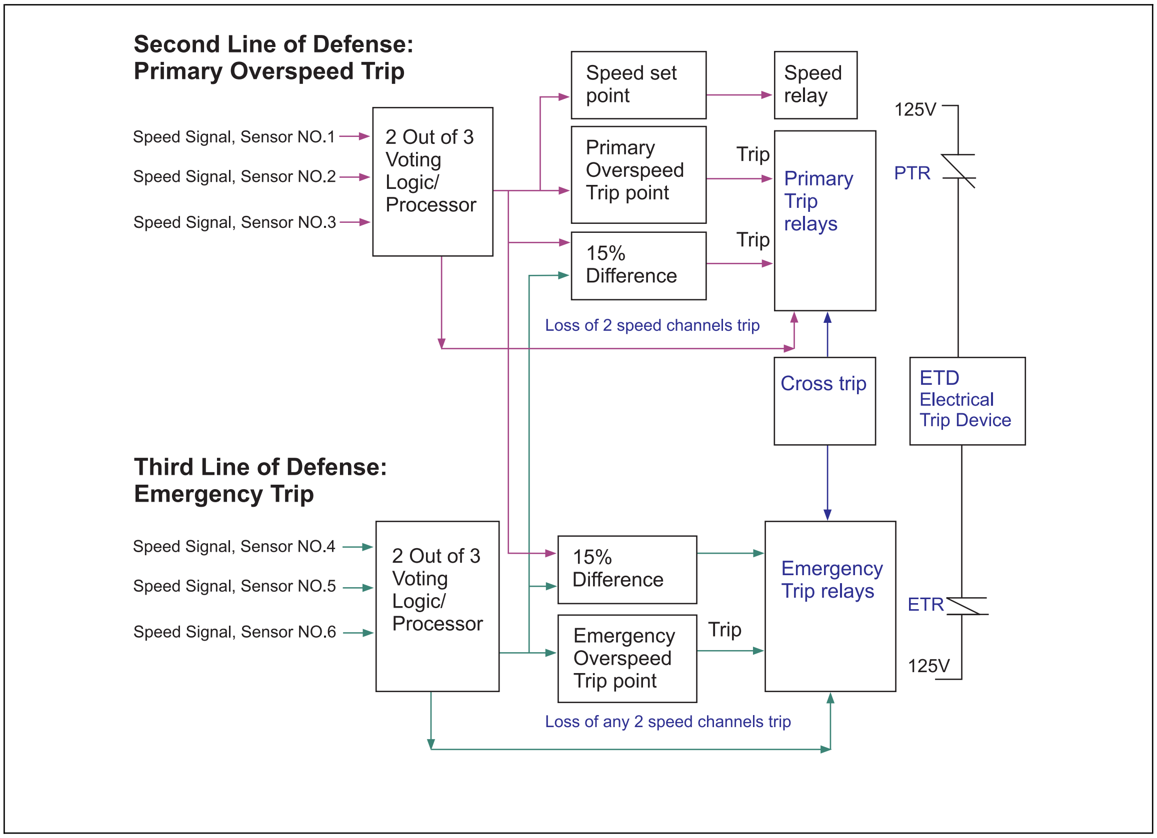

Fig. 3.2-2. Electronic overspeed detection system

3.2.1 Electronic Overspeed System

Electronic overspeed protection systems are proven to prevent losses, improve reliability, and minimize process interruptions and property damage. These are good reasons for providing the electronic systems on new machines and retrofitting existing ones. Replacing a mechanical overspeed protection system with an electronic one has the following advantages:

- The electronic system does not rely on mechanical parts or actuation.
- The electronic system allows for testing without the need to change a machine's speed.
- Trip speed will not change over time.
- The electronic system provides for precise trip speed and digital set point.
- The electronic system provides a control system interface.
- The electronic system is fault tolerant.
- The electronic system requires no physical contact with shaft or mechanical trip lever.
- The electronic system can be tested periodically with a signal generator with minimal risk to the operation of the turbine.
- There is no need to stress the turbine by taking it to the overspeed set point.
- There is no need to calibrate devices.
- There is a significant savings in time to perform tests.

3.2.2 Triple Redundant Electronic Overspeed Protection System

The advantage of a triple redundant electronic overspeed protection system is that it can prevent false trips and prevent loss of production.

Six magnetic-type probes are used in conjunction with a multi-toothed wheel on the steam turbine shaft to sense the turbine's rotational speed (see Figure 2.1.2.1). A primary set of three probes, voted two-out-of-three, is used for speed control, speed indication, zero-speed detection, and primary overspeed protection. The other set of three, also voted two-out-of-three but in separate and triply redundant protection computers, is used exclusively for emergency overspeed protection. Probe channel failures are detected when any single channel signal differs from the voted value by more than 5%. Failure of any channel will generate an alarm. Failure of any two probe channels out of the three in a set will trip the turbine. Also, a difference in the speed determination of more than 15% between the two processor outputs will trip the turbine.

Values equal to or greater than the trip set point will de-energize the primary trip relays (PTRs). The PTRs, in turn, will de-energize the electrical trip devices (ETDs) and trip the turbine. Values equal to or greater than the trip point will de-energize the emergency trip relays (ETRs). The ETRs, in turn, de-energize the ETDs and trip the turbine. The emergency overspeed trip subsystem is a component of the protection system, a completely independent set of triply redundant computers. The emergency overspeed trip system will also signal the control servo valves to force the main steam emergency stop valve closed. The emergency overspeed trip systems are also ″cross-wired″ so that, should one trip, the other will be forced to trip as well.

3.2.3 Disadvantages of Mechanical Overspeed Systems

Mechanical overspeed trip bolts sometimes fail to act completely. With age, these systems become more difficult and costly to maintain, and are often incapable of performing advanced functions to improve reliability and prevent losses. They are also prone to the formation of varnish and sludge in the moving parts due infrequent exercising, and if oil rarely circulates through it. This may prevent internal components from moving adequately, compromising its functionality.

Testing mechanical overspeed systems can be dangerous and very expensive. To test the system, the machine must be physically made to overspeed, requiring an interruption of the production process. If the bolt or cantilever device fails to operate during the test, it may be difficult to manually react in time to prevent unconstrained overspeed and the ensuing damage. Therefore, FM prefers the use of electronic protection systems in place of mechanical overspeed systems.

3.2.4 Modernization of Steam Turbine Mechanical Overspeed with an Electronic System

When modernizing a mechanical overspeed trip systems it should be replaced with a failsafe (deenergize to trip) electronic overspeed system. Steam turbine OEMs rarely specify mechanical overspeed trip devices on new modern steam turbines (an exception may be general-purpose mechanical-drive steam turbines), and clients are modernizing older turbines by replacing the mechanical systems with electronic systems (using the OEM or other qualified contractor).

When modernizing a mechanical overspeed trip system, the obsolete mechanical trip system should be fully removed to prevent the potential for a single point failure, malfunction (sticking or seizing), unintended trips, and maintenance costs.

Electronic overspeed systems may vary in their details from one provider to another, but should include the following key features: Modern turbine electro-hydraulic control (EHC) consisting of the high-pressure hydraulic power unit and trip system used to position the steam turbine valves.

These systems include all the control devices and instrumentation that interfaces to the turbine control system. The new EHC systems include enhanced decision logic, redundancy, and improved software. Installing new fail safe (deenergize to trip) trip solenoid valves to shut the steam stop valves is also required for improved reliability.

3.2.5 Steam Turbine Generator Motoring

Leaving the generator breaker closed after stopping the steam supply will cause the generator to act like a motor. motoring operation is harmful and can lead to overheating damage in the steam turbine and generator. After unloading to negative power, the generator acts as motor and drives the steam turbine at synchronous speed (grid frequency). The problem is compounded with windage losses due to lack of ventilating steam flow to carry heat away. Overheating of the internal parts of the steam turbine due to motoring operation can lead to blade shim migration, creep deformed blades, significant rubbing, bent or broken rotors, and possible destruction of the entire steam turbine generator set.

3.2.5.1 Steam Turbine Generator Motoring Protection

After turbine trip, the sequential tripping circuit (reverse power relay 32) is designed to detect generator motoring and open the GCB to disconnect the unit from the grid (see Data Sheet 5-12, *Electric AC Generators*, for guidance on motoring prevention).

3.3 Vibration Monitoring

The aim of vibration monitoring is to detect change in the machine's motion from its position of rest. It is normal for all machines, even in peak performance condition, to vibrate and make noise. The level of vibration is dependent on the operating condition of a mechanical system; if vibration increases to an unacceptable level, it is a sure indication that some component is deteriorating and systems are failing. Using reliable vibration monitoring provides protection and information for detailed analysis to control processes and keep turbine components healthy.

The online continuous vibration monitoring system for steam turbine generator drives is much the same as for industrial turbines.

Proximity transducers provide superior machinery diagnostic information. They allow a greater degree of machinery protection because they are sensitive to problems that originate at the rotor (such as bearing preloads, bearing wear, and insufficient bearing lubrication) that may not transmit faithfully to the machine's casing and/or are observable with casing-mounted transducers.

3.3.1 Vibration Causes

- Unbalanced rotor due to broken or loose rotating parts
- Bowed rotor, rotor total indicator run-out (TIR) out of tolerance
- Bearing failure, improper lubrication
- Rotor misalignment, axial and radial clearance out of tolerance, rotor floating
- Worn coupling, gear wear/damage
- Steam flow irregularities: low flow may excite various modes of vibration in the blades
- Rotor blades rubbing against stationary casing
- Foundation trouble, anchor bolts and shim packs
- Cracked or excessively worn parts

Note: Unbalanced and misaligned rotors are the most frequently encountered steam turbine problems.

3.3.2 Vibration Detection, Alarm, and Trip

Vibration monitoring is necessary to assist in the evaluation of a machines condition.

3.4 Water Damage Prevention Monitoring Systems

3.4.1 Steam Turbine Hazards: Water Induction

The introduction of water into any part of a turbine operating at high speed and temperature can cause serious damage to the rotor, blades, vanes, nozzle diaphragms, sleeve and thrust bearing, and seals. A significant amount of water induction damage to a turbine is caused from water collection in steam lines, turbine casings, extraction lines, improper valve lineups during startup and shutdown, and excessive tube leakage from feedwater heaters. High water level in the steam generator drums can carry over to the superheaters or reheaters and into the turbine, and will damage turbine internal components resulting in turbine failure.

Water induction has the following effects:

- Thrust bearing failure. Water carryover from the steam generator may impose a load on the thrust bearing that is sufficient to cause bearing failure.
- Damaged vanes, seals, and blades. Axial movement of the rotor can result in impact between rotating and stationary components.
- Thermal cracking. Water from any source may contact metal parts that are at temperatures high enough to result in thermal cracking.
- Rub damage. Water introduced from the main steam or reheat lines can cause differential expansion problems between rotating and stationary parts in the form of axial rubs. Water backing up from extraction lines may cause contraction of the lower part of the shell, giving a humping effect that can lift diaphragm packing against the rotor, causing radial rubs.
- Bowing of the rotor results when packing rub causes uneven heating on the rotor surface. This additional distortion further increases the intensity of rubbing. Packing, spill strips, and blade shroud bands are the most frequently damaged parts. Water induction may cause the casing to become warped (thermal distortion) leading to subsequent rubbing. Heat-treating either in-situ, onsite in a temporary furnace, or offsite may be required to restore its shape.
- Permanent warping or distortion. This condition may result when metal parts are subjected to severe quenching, and can cause steam leaks in valve and shell joints. Diaphragm dishing and rotor bowing caused by water quenching can result in distortion to the extent that turning gear motors will load and trip following engagement.
- When a turbine generator is tripped and the steam admission stop valves (main, reheat auxiliary, as applicable) are closed, the pressure in the turbine drops to the vacuum maintained in the condenser. Steam in the extraction lines is prevented from expanding back through the turbine by the non-return valves in the extraction lines. If a non-return valve fails to close when subjected to the back pressure, steam from the feedwater heater serviced by that line flows back and can drive the turbine into overspeed if the generator breaker is also opened. Condensate in the heater flashes into steam close to the saturation line, and flows back into the turbine. This adds to the energy available to overspeed the turbine. However, in the case of large utility turbines, there have been incidents where the cold steam impinging on one side of the inner shell has cooled it rapidly, causing the inner shell to deform. The resulting severe rotor rub prevented the overspeed, but the blading damage was extensive.

3.4.2 Mechanical-Drive Steam Turbine Water Induction Prevention

Mechanical-drive steam turbines are often powered by excess process steam, a waste heat recovery boiler, or a cogeneration process, in which steam quality can be variable. Steam should be free from moisture, and preferably superheated per the turbine OEM specification. Failure to remove condensed water from steam lines or the turbine casing may result in steam path erosion, thrust bearing failure, rotating to stationary component contact, loss of steam path labyrinth seals, and poor performance.

If a water induction event is suspected, a review for a step change in the turbine's historical isentropic efficiency, or throttle pressure in relation to output or power, may provide an indication of when it happened and the ability to correlate it to certain events.

Steam turbines that receive steam from a remote source are more likely to experience water droplet erosion because the steam tends to condense as it travels through the lengthy piping network. Mechanical-drive steam turbines require a moisture separator in the supply piping, and bucket traps are used to drain any captured condensate from the steam separators. A source of water in mechanical-drive turbines could be from long extraction piping systems that connect to low pressure steam systems or let down stations.

3.5 Water Quality and Steam Purity

Steam purity refers to the amount of all non-water components (minerals, contaminants, gasses) contained in the steam. Steam quality (dryness) is a measure of moisture in the steam expressed as the percentage of water vapor in the steam/water mixture. Water quality and steam purity control systems provide precise system monitoring for solids content, liquid, and vapor contamination in the steam leaving the boiler. Monitoring systems protect the steam turbine components in the steam flow path from erosion, corrosion, deposits, stress fatigue, and failures. Impurities are in the form of dissolved, partially dissolved, or suspended solids. The most common solids are sodium salts, calcium, magnesium, iron, and cooper. Gaseous impurities (mostly found in low-pressure steam properties) include carbon dioxide, ammonia, nitrogen, amines, and Silica.

Sources that can impact purity include make-up water, boiler-water carry over, accelerated corrosion, condensate contamination by condenser leaks, surface condenser leaks, attemperator water, breakthrough in cation exchanges and condensate polishers, water treatment chemical addition (i.e., oxygen scavengers). Steam purity is expressed in parts per billion or sometimes parts per million of the impurities.

For drum-type boilers it is important that sodium and cation conductivity in steam is measured continuously or on a frequent basis. Even when the boiler feedwater quality and monitoring system is good, sodium can enter boilers when they use phosphate and NaOH alkalizing chemicals in the boiler/HRSG. Attemperator water that is injected directly into the steam is often another source of impurities, including oxides/hydroxides from the feedwater system. Plants using all-volatile treatment systems are less prone as they do not use phosphates or NaOH alkalizing chemicals.

Steam sample analysis methods include, but are not limited to, the following:

- Sodium Analysis – Ion Specific Electrode (ISE): Provides immediate results, and can be continuously monitored and recorded with reasonable accuracy.
- Sodium Analysis – Flame Photometry: Lab verifiable, and is accurate.
- Sodium Analysis – Ion Chromatography: Lab verifiable, very accurate, and can be used to verify other methods.
- Specific Conductivity: Most flexible method, continuously monitored, is influenced by dissolved gasses and volatiles, less accurate than sodium methods.
- Calorimetric: Less accurate, not applicable above 600 psig.
- Gravimetric – Requires large sample size and steam flow measurements, cannot detect spikes in impurity, and cannot provide real time results.

Sampling points and measurements:

- Sodium samples are taken from superheated steam supply to the turbine.
- Makeup water: cation and specific conductivity, pH, sodium, and silica.
- Condensate return: cation and specific conductivity, copper, sulfates, pH, sodium, and silica.
- Feedwater treatment plant: pH, specific and cation conductivity is measured before and after ion exchangers, softeners and reverse osmosis systems and condensate polishers. Sodium is measured at the inlet and outlet of the ion exchangers.
- Feedwater entering boiler: pH, dissolved oxygen, sodium, conductivity.
- Boiler water: pH, conductivity.
- Saturated steam: sodium and cation conductivity.
- Superheated steam: sodium, cation, and specific conductivity.

Steam quality is expressed in the percentage of steam to steam and condensate. Steam quality is extremely important in mechanical-drive steam turbine applications because water impinging on the blades could result in turbine blade moisture erosion. Steam quality can be difficult to measure and requires a calorimeter (Separating Calorimeter or Throttling Calorimeter) and accurate readings of steam temperature, pressure, and steaming rate. For mechanical-drive steam turbines poor steam quality is likely the result of one of the following:

- Malfunctioning steam traps and drains
- Lack of insulation on steam lines
- Boiler-water carry over

3.6 Steam Turbine Shaft Seal and Gland Seal System

3.6.1 Advantages of a Gland Seal System

A gland seal system ensures sealing of the turbine rotor/shaft (see Figure 3.6.2-1). The system provides the following benefits:

- Improves cycle efficiency and turbine performance
- Eliminates lube-oil contamination due to condensing water migration into the oil from the turbine shaft seals, and achieves longer service life before oil change
- Protects the turbine rotor edge seals from damage, and limits steam vapors around the machine that are usually toxic due to additives found in the machine
- Reduces the humidity around the machine, resulting in safer operation of all electric devices installed in the area• Prevents leakage of air into the condenser and keeps steam from blowing out into the turbine hall

The following problems can result if a gland seal system is not used:

- Steam can migrate and condense in the bearing lube-oil system.
- Degradation of the lube-oil characteristics
- Pollution due to the release of toxic vapors containing additives from the machine

3.6.2 System Function and Operation

The gland seal system provides low-pressure steam slightly above atmospheric pressure, usually 1.5 to 2.5 psi (10 to 17 kPa) to the steam turbine glands and seal areas at rotor shaft ends. The source of gland sealing steam flow changes from the startup phase to the normal operating phase. While the turbine is on turning gear and at warm-up period and during the startup sequences, it is necessary to provide an auxiliary source of sealing steam until an adequate pressure and quality of steam becomes available from the process. During a startup, vacuum must be established in the condenser, and the arrows in Figure 3.6.2-1 represent the startup mode gland steam supply. In normal operation, leak off steam from the HP end sealing gland is often used to supply steam sealing pressure to the IP and LP gland seal ends. During normal operation, enough steam escapes through the HP turbine shaft gland seals that it can be used as a seal steam supply for the IP and LP turbine shaft gland seals. The excess steam not used for gland sealing steam is dumped to the main condenser through the seal steam leak-off valve.

In general, the steam seal header pressure and temperature are regulated automatically for specific turbine and operation requirements. A let-down pressure control valve and desuperheater water spray are used in the process. (See Figure 3.6.2-1)

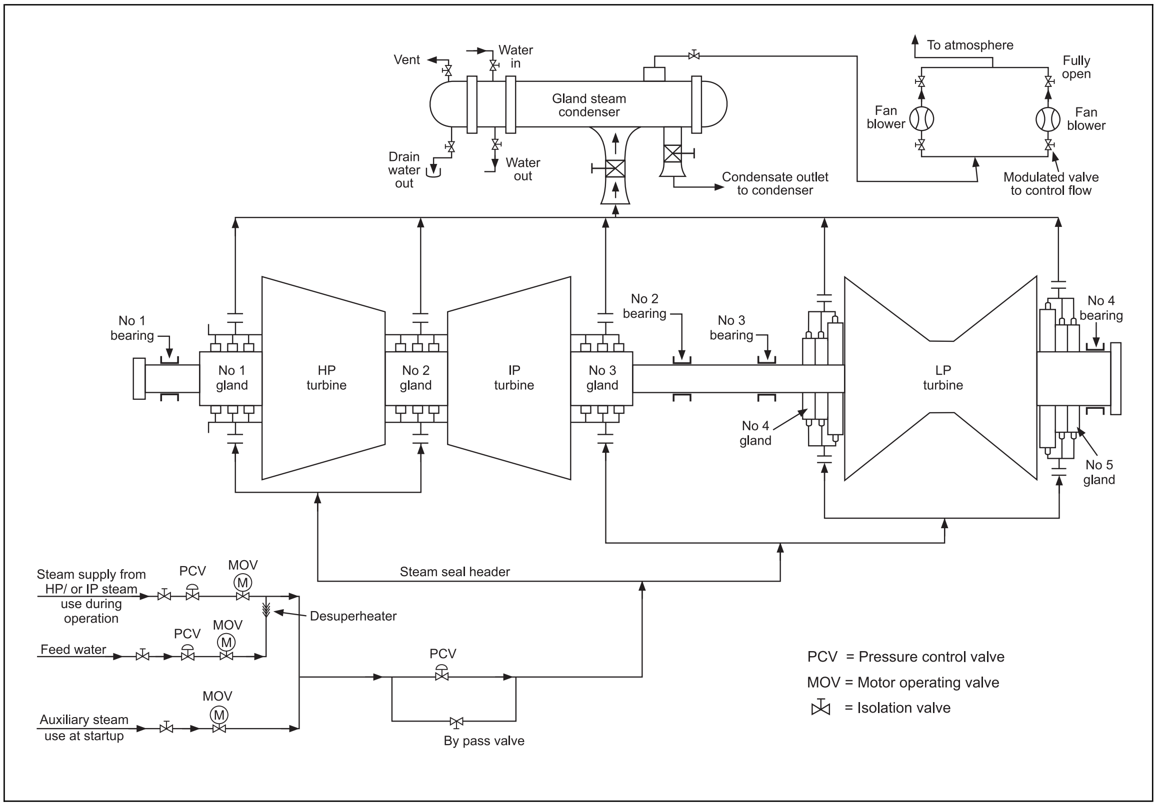

Fig. 3.6.2-1 Typical gland sealing steam supply during startup to establish a vacuum and until HP gland leak off pressure is established

A series of backed segmented packing rings are fastened in the bore of the turbine shells. (See Figure 3.6.2-2.)

These rings are machined with specially designed teeth that are fitted with minimum radial clearance.

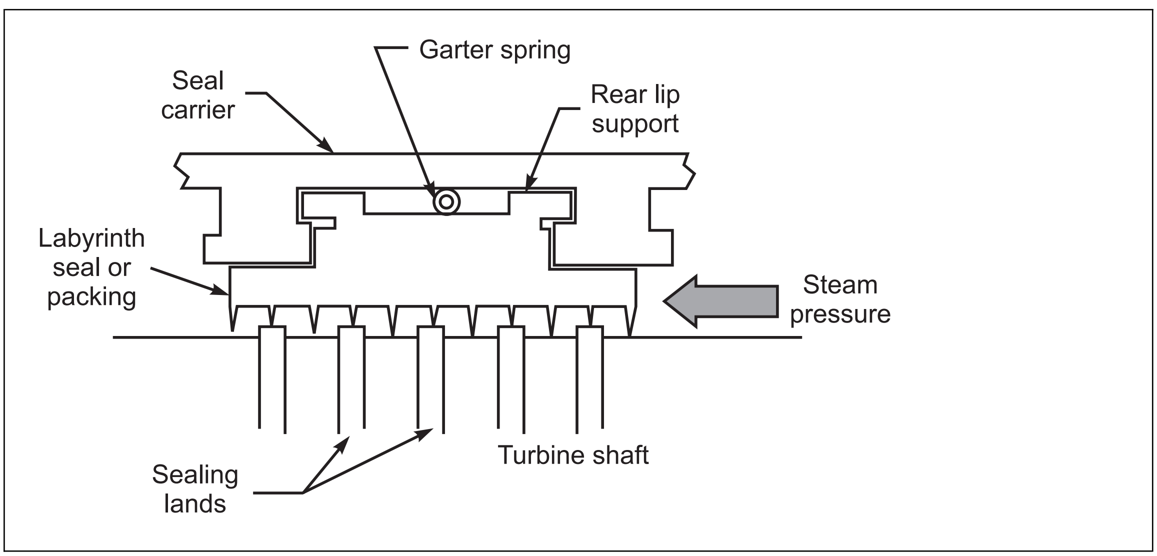

Fig. 3.6.2-2. Typical spring-type shaft-sealing system

4.0 REFERENCES

4.1 FM

Data Sheet 5-12, *Electric AC Generators*
Data Sheet 5-20, *Electrical Testing*
Data Sheet 5-23, *Design and Protection for Emergency and Standby Power Systems*
Data Sheet 5-28, *DC Battery Systems*
Data Sheet 7-45, *Safety Controls, Alarms, and Interlocks*
Data Sheet 7-77, *Testing of Engines and Accessory Equipment*
Data Sheet 7-95, *Compressors*
Data Sheet 7-101, *Fire Protection for Steam Turbines and Electric Generators*
Data Sheet 7-109, *Fuel Fired Thermal Electric Power Generation*
Data Sheet 7-110, *Industrial Control Systems*
Data Sheet 9-0, *Asset Integrity*
Data Sheet 10-8, *Operators*
Data Sheet 13-7, *Gears*
Data Sheet 13-18, *Industrial Clutches and Clutch Couplings*
Data Sheet 13-26, *Internal Combustion Engines*

UTH - *Fire Protection for Turbine and Generator Oil Systems* (P0310)
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APPENDIX A GLOSSARY OF TERMS

Alternative service provider (ASP): An entity that is not affiliated with the original equipment manufacturer.

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

Blue blush: Oxidation of metal that is time and temperature dependent. Typical of valves that are mechanically bound and have limited movement.

Coast-down time: When a steam turbine trips and all steam supply is cut off, coast-down time (also called run-down time) is the time it takes for the rotor to coast down from its rated operating speed to a stop or turning gear speed (~6 RPM). Mechanical-drive steam turbine coast-down time is dependent on the rated operating speed and if it's a non-condensing back-pressure, extraction or condensing unit.

Cogeneration: Electric-generating plants that produce a combination of electricity and process steam to a host are defined as cogeneration plants. Cogeneration (Co-gen) plants may be installed in municipalities, industrial plants, commercial complexes, or institutional facilities such as hospitals and religious establishments for the purpose of selling electric power to utilities under the provisions of the National Energy Act of 1978. A subdivision of this act is termed the Public Utilities Regulatory Policies Act (PURPA). It requires that a percentage of the thermal steam energy produced be employed usefully, such as in a process or for heating.

Cold start: A type of start that is typically defined by admission point temperature or time between shutdowns and on turning gear (i.e., standstill). FM considers standstill time for cold starts as more than 60 hours.

Cold steam: As a general rule, ″cold steam″ may be defined as steam inducted into the steam turbine with the steam temperature more than 100°F lower than the temperature expected for the operating condition of the turbine; or loss of measurable superheat.

Cycling unit: Start/stop cycling involves power generating equipment that is turned off at least 24 times per year to satisfy economic market conditions, load demand requirements, or maintenance.

Differential expansion: Differential expansion occurs due to the temperature and axial thermal growth rate difference (expansion or contraction) between the rotating (rotor) and stationary (diaphragms and seals) components. Differential expansion occurs during startup, shutdown, low-load operation, and load swings. The largest temperature and axial difference typically occur during cold starts when the rotor heats up faster than the stationary components, and after some time the rotating and stationary components reach a steady-state thermal equilibrium where axial difference is the lowest. The most common method of axial measurement is by using eddy current sensors.

Duty Cycle: is a term used to define a turbine’s operating profile based on the annual number of starts or hours accumulated. A high duty cycle is defined as annual start-stop cycles greater than 100 or annual operating hours greater than 5,000. Low duty cycle is defined as annual start-stop cycles less than or equal to 100, or annual operating hours less than or equal to 5,000.

Exercising valves: Valves that remain at a steady state position, where their movement could be frozen by steam deposits or valve stem oxidation (blue blush), require routine valve exercising to ensure they open and close as intended. This controlled test is performed online by moving the valve stem from its steady state position, a couple of inches open and closed, without upsetting the process flow or making a significant change to the operation. Operators usually perform an offline full stroke test during a scheduled shutdown because it impacts the process. But, when a safety integrity function requires more frequent testing, a partial stroke test is performed while the valve is online without impacting the process. Partial stroke testing can be accomplished online manually or with a digital valve controller. The partial stroke functionality can be initiated locally or remotely via a distributed control system (DCS). In a matter of seconds, the system completes a partial stroke of the valve, and the turbine operators can quickly determine if the valve is functioning properly or requires attention.

Fail-safe condition: When a piece of machinery or other component reverts to a safe condition (deenergize to trip) in the event of breakdown or malfunction.

False trip: A condition in which the turbine appears to be tripped, and the trip oil pressure indicates zero, the emergency stop valve (ESV) position switch indicates closed (or both signs are identified simultaneously), but the generator keeps producing power (P > 0 MW). This condition can happen if the ESV or non-return (check) valve fails to close completely. A visual inspection of the valves may mislead the operator that these valves are closed, but a small amount of steam leakage is enough to continue generating some level of power. The recommended solution is to isolate the steam to the turbine from all inlet, re-heat, and extractions steam pipes by tripping the boilers and/or closing manual isolation valves.

The generator circuit breaker must not be opened in any circumstance since this would cause the turbine to instantly overspeed. It is very important to differentiate this condition from motoring, in which the generator is consuming power (P < 0 MW).

Flexible operation: A term more commonly used to cover various modes of operation, and occasionally synonymous with load following or cycling. FM defines “flexible operation” as any type of operation other than baseload, including the following main operational modes:

- Load following/load cycling

- Minimum load operation
- Higher ramp rate (fast start, fast forced cool down)

Flexible operations can be due to a plant's cost of fuel and its competition with cheaper forms of electrical generation (renewables or combined cycle plants). Conventional power plants may be called upon to cycle to smooth load fluctuations produced by renewable energy, primarily wind and solar energy.

Functional overspeed test: A test of the overspeed trip system, performed at or below rated overspeed, to verify the entire overspeed system component integrity. The full functional test ensures that the entire system is tested in concert with one another and includes verification of the mechanical or electronic overspeed trip mechanisms, positive closing of the main/emergency steam stop and control valves, the hot reheat intercept valves, the extraction non-return valves, and for generator-drive steam turbines, the proper functioning of the reverse power relay 32 to disconnect/open the generator breaker.

Heat rate: The measure of energy efficiency that defines how much fuel expressed in British Therma Units (Btu) it takes to generate a kilowatt-hour (kWh)of electricity (expressed as Btu/kWh).

High ramp rate: An indicator of how quickly the turbine changes its output, typically expressed in MW per minute or % power per minute. Refer to OEM user manual for defined ramp rate thresholds. Typically, high ramp rate leads to a hot start of less than 3 hours and a cold start of less than 5 hours. Combined-cycle units may have the capability to achieve higher ramp rates based on design and/or operational parameters, which may not apply to the above.

Hot start: A type of start that is typically defined by admission point temperature or time between shutdowns and on turning gear (i.e., standstill). FM considers hot start standstill time as less than 12 hours.

Integrity operating window (IOW): Sets of limits used to determine the different variables that could affect the integrity and reliability of a piece of machinery or process. Machinery operated outside of IOW's may cause otherwise preventable damage or failure.

Intercept valve: Reheat steam turbines with an intermediate pressure (IP) turbine section, are equipped with intercept valves in the hot reheat supply piping. The intercept valves are always open during normal operation of the turbine. During a turbine shutdown or trip, the intercept valves close to isolate the steam stored in the boiler reheater and associated piping, preventing turbine overspeed damage.

Isentropic efficiency: Steam turbines experience degradation over time that affects efficiency and performance. Some sources of degradation can be increased worn sealing clearance, solid particle erosion (SPE), moisture erosion, steam path deposits, and foreign object damage. Isentropic efficiency expresses how an actual steam turbine's efficiency and performance compares to its new and clean condition (the ideal process without any degradation). Efficiencies are defined to be less than 1, therefore turbine Isentropic efficiency is defined as actual turbine work divided by Isentropic turbine work. Well-designed large turbines may have isentropic efficiencies above 90 percent. Small turbines may have isentropic efficiencies below 70 percent.

Layup: A state of preservation that will maintain equipment and system integrity to prevent corrosion. Various strategies can be employed depending on duration, resources, effectiveness, and best-practices. For a steam turbine, warm dehumidified air is used to prevent moisture condensation pitting and loss of passivation layer on the steam path surfaces (rotors, blades and diaphragms).

Legacy unit: In the context of this document, legacy units are considered steam turbines manufactured prior to 1990, without features that enable cyclic operation. Prior to 1990, fossil steam turbines operated in a base load profile. In the early to mid-2000s, turbine manufacturers added features to improve their cycling capability. For example, more generous clearances between the rotor and stationary parts are required to allow for differential expansion during startup, fast ramp rates, and rapid load swings.

Load following unit: A generating unit operated over a range of MW versus standard base load MW output to satisfy grid demand. Due to load changes required for these output variations, thermal stresses may see a significant increase. Significant load following (SLF) is when a unit's load experiences a load change of 20% or more of the full capacity.

Low-load condition: A term synonymous with "turndown," although site and OEM definitions may vary regarding the actual load percentage achieved of full load capacity to qualify for this operational mode. FM considers less than 30% of full load (e.g., 30 MW where 100 MW is full load) and a unit's annual average load factor as the basis for evaluating low-load conditions. Annual average load factor is a ratio of the average load of a unit during a year versus full load capacity during that same year.

Motive steam system: Systems that supply steam to a turbine for the primary purpose of power production. The term ″motive steam″ is intended to include steam lines typically referred to as main, hot and cold reheat, high-pressure, intermediate-pressure, low-pressure, and admission. Motive steam lines as defined in this data sheet do not include lines typically referred to as extraction steam and gland steam seal lines.

Overspeed testing: The turbine overspeed trip system provides protection from an uncontrolled overspeed and catastrophic failure of the steam turbine and its driven equipment. Protection is provided in the turbine trip system to close the steam valves and stop the turbine speed. Whether a full functional test of the entire system is performed or a simulated electronic overspeed test is performed, It is not necessary to test the overspeed system by running the turbine up to the set point trip speed (typically 110% of rated operating speed). Testing at lower trip speeds does not reduce turbine service life and imparts lower centrifugal stresses on older turbine blades, rotors, and driven equipment (fans, pumps, compressors, and generators).

Partial-arc admission: Admission of steam into a steam turbine through only a part of the steam inlet nozzles.

Peaking unit: A generating unit that undergoes load following profiles but with additional attributes of high load-change ramp rates. Units of this profile may see increased thermal stresses due to the cyclic nature of the required load changes.

Phase transition zone (PTZ): Area in the turbine where condensation forms, typically towards the latter stages of the low-pressure turbine. Also known as the Wilson line.

Roll off: An unintended, uncontrolled increase in steam turbine RPM during startup before the operator intentionally actuates the control valves to open. Steam leaking past the control valves allows the rotor to accelerate without control during a startup, and can occur during a cold, warm, or hot start. The condition is a personnel safety issue and can be a mechanical integrity concern if the speed dwells at a rotor critical speed.

Runback: A reduction in load due to upset conditions during operation.

Sequential trip: Involves tripping the steam turbine generator, then tripping the generator breaker and field breaker on reverse power. This tripping method reduces the risk of an overspeed of a steam turbine driving a generator. It is used for normal shutdowns and turbine-initiated trips. All motive steam power to the turbine must be isolated first as a permissive to allow tripping of the generator breaker. Automatic sequential trip logic uses the indication of a turbine trip supervised by the generator reverse power relay 32 to initiate a trip signal to open the generator main circuit breakers.

Service age: The actual operating hours and duty cycles of the machinery components (not the chronological age from the original machinery installation date). For example, if an old steam turbine has had all of its rotors, bearings, and diaphragms replaced, its service age is less than its chronological age.

Simulated overspeed test: A test in which the functioning of the overspeed response, signal transmission, and emergency shutoff valve control respond to a simulated overspeed signal. Simulated tests typically do not test the emergency trip device and the steam shutoff valves. The test can be conducted while the unit is online, without actually reaching overspeed. A speed signal is created by a function generator to simulate an overspeed condition. This simulated test may include confirming mechanical/hydraulic operation of a part of the trip system or performing some simulated test on part of the electronic system, all while the trip circuit is partially blocked.

Steam Turbine Types (refer to Appendix C for more information):

A. Steam turbines driving an electric generator for commercial electrical sale or industrial plant electrical load and in some cases, for extraction steam.

B. Mechanical-drive steam turbines (steam turbines in applications driving equipment other than generators).

1. General-purpose mechanical-drive steam turbines: Small steam turbines under 6,700 hp (5,000 kW) with basic features for good reliability at a lower capital cost. They are used to drive equipment that is usually spared, relatively small in power, or is in non-critical service. Some examples are air conditioning chillers, smaller pumps, fans, paper mill line shafts etc.

2. Special-purpose mechanical-drive steam turbines: Medium and large steam turbines greater than 6,700 hp (5,000 kW) up to a rating of 405,000 hp (302,008 kW), designed for maximum equipment reliability. Used to drive equipment that is not spared, is large in horsepower, or is in critical service. Some examples are large, forced draft/induced draft fans, boiler feed pumps, and large process compressors, etc.

Torsional frequency: Frequency in which inertia and stiffness are completely in sync.

Triple modular redundant (TMR): A fault-tolerant system in which three systems monitor a process and the results are processed by a voting system to produce a single output. If any one of the three systems fails, the other two systems can correct and mask the fault. If the voter fails, the complete system will fail.

Turndown: A generating unit that undergoes load changes to minimum operating parameters, typically to limit start/stop cycles while remaining connected to the grid.

Two-shifting: A term used for a unit that starts up and shuts down daily.

Warm start: A type of start that is typically defined by admission point temperature or time between shutdowns and on turning gear (i.e., standstill). FM considers warm start standstill time as more than 12 hours, but less than 60 hours.

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).

April 2025. Interim revision. Clarifications were made to the following:

A. Provided clarifications for steam turbine shaft driven lube oil pumps.

B. Provided clarification - non-return valves are not required for back pressure steam turbine exhaust lines.

July 2024. Interim revision. Clarifications were made to the following:

A. Updated Turbine Water Induction to TDP-1 2023.

B. Provided clarifications for lube oil DC power supply systems.

C. Added reference to Data Sheet 7-109, *Fuel Fired Thermal Electric Power Generation Facilities*, for recommended startup permissive guidance for lube oil systems.

D. Added clarifications to emergency lube oil system testing.

E. Added lube oil cooler temperature control valve guidance.

F. Emergency operating procedure to manually rotate a hot rotor to prevent rotor bowing.

G. Added guidance to test, repair or replace emergency lube oil pumps which have experienced a thermal overload alarm.

H. Turning gear inspection and maintenance guidance for units in flexible operation.

I. Provided a redirect to Data Sheet 7-109 for recommended equipment layup procedures.

J. Added DC emergency lube oil pump motor thermal overload alarm to Table 2.1.1-1.

K. Added inspection and dismantle intervals for boiler and HRSG main steam header stop valves to Tables 2.2.2.5.1.1-1, 2.2.2.5.1.1-2, 2.2.5.1.2-1 and 2.2.5.1.2-2.

L. Added a definition for Duty Cycle in Appendix A.

January 2024. Interim revision. Clarifications were made to the generator drive steam turbine overspeed testing requirements in Section 2.2.1.1.1 for consistency with Data Sheet 13-17, *Gas Turbines.*

July 2023. Interim revision. Editorial changes made for additional clarity on service life and remaining useful life terminology.

July 2022. Interim revision. Made editorial changes made to provide additional clarity on steam turbine bulletins/alerts.

January 2022. Interim revision. The following editorial changes were made:

A. Clarified Tables 1 and 1a, Protective Devices, Alarms, and Trips, on emergency overspeed trip, water induction, and location of high temperature oil sensors.

B. Clarified Table 2, Steam Purity for General Purpose Mechanical-Drive Steam Turbine, on sampling intervals.

C. Clarified when a mechanical overspeed trip system should be modernization to an electronic overspeed system.

D. Added guidance for low duty cycle generator-drive and mechanical-drive valve testing, maintenance, and dismantle intervals.

E. Added guidance for generator and mechanical drive steam turbine valve testing and dismantle intervals, and turbine dismantle intervals.

F. Clarified guidance on valves that are not equipped for online exercising, removing the recommendation to modify or replace them at the next opportunity.

G. Added guidance to steam turbine operation for breaking condenser vacuum earlier than the OEM recommendation.

H. Added equipment breakdown sparing guidance in contingency planning for mechanical-drive steam turbines in critical service.

I. Added guidance to develop an equipment contingency plan to prepare the response to a premature failure of the rotor in service.

J. Clarified general sparing guidance, see Data Sheet 9-0, *Asset Integrity*.

K. Clarified guidance on modernization of steam turbine mechanical overspeed with an electronic system, removing the recommendation to upgrade at the next opportunity.

L. Clarified guidance on steam turbine shaft seal and gland seal system function and operation and Figure 3.6.2-1.

M. Removed guidance for generator-drive and mechanical-drive steam turbine emergency stop and non-return valves to be modified or replaced at the next opportunity to allow for online exercise testing.

N. Clarified Appendix A definitions for cycling units and flexible operation.

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

July 2021. Interim revision. The following significant changes were made:

A. Clarified Section 2.2.2.1, Emergency Lube-Oil Testing, and changed the numbering format.

B. Deleted references to obsolete Data Sheets 12-17 and 6-23.

C. Changed Appendix A “Steam Turbine Types,” Section B, Items 1 and 2 from 10,000 hp (7457 kW) threshold to 6,700 hp (5,000 kW).

April 2021. Interim revision. The following significant changes were made:

A. Added recommendations to Table 1, Protective Devices, Alarms, and Trips, for generator-drive steam turbines. Also added a separate table (Table 1a) for mechanical-drive steam turbine protective devices.

B. Added recommendation for lube-oil and seal-oil DC systems, single-point failures, and mechanical-drive steam turbine lubrication types.

C. Added recommendations for turbine water induction prevention for mechanical-drive steam turbines.

D. Added recommendation to ensure control systems comply with OS 7-110, *Industrial Control Systems, for cyber risk*.

E. Added recommendation for electronic overspeed and mechanical bolt system testing and prevention (generator-drive and mechanical-drive steam turbines).

F. Added recommendation for lube-oil and seal-oil condition monitoring programs.

G. Added recommended turbine valve testing and dismantle intervals for mechanical-drive steam turbines.

H. Added recommended steam turbine maximum dismantle intervals for generator-drive and mechanical-drive steam turbines.

I. Updated recommendations in the Change in Operating Profile section (flexible operations) regarding rotor critical speed, low-load avoidance zones of operation, and layup.

J. Added guidance for lube-oil analysis, and types of pumps for mechanical-drive steam turbine lubrication.

K. Added guidance for overspeed protection systems for generator and mechanical-drive steam turbines.

L. Added guidance for modernization of steam turbine mechanical overspeed with an electronic system.

M. Added guidance for steam turbine generator motoring prevention.

N. Added guidance for mechanical-drive steam turbine water induction prevention.

O. Added guidance for water quality and steam purity.

P. Added guidance for online valve exercising and turbine roll-off.

Q. Added guidance for flexible operation to change in operating profile.

R. Added 25 new terms and definitions to Appendix A.

S. Added cross-compound and single shaft steam turbine types and SSS clutch maintenance intervals to Appendix C.

January 2021. Interim revision. Added supporting terms to the definition of “flexible operation” in Appendix A, Glossary of Terms. .

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

July 2020. Interim revision. The following significant changes were made:

A. Updated contingency planning and sparing guidance.

B. Added lube-oil system and flexible operation guidance.

C. Updated Section 2.2.12, Operators.

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

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

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

October 2018. Interim revision. Minor editorial changes were made.

January 2018. Interim revision. Minor editorial changes were made.

October 2017. Interim revision. Minor editorial changes were made. Equipment Alert EA 2017-Jun-08, *GE Steam Turbine Trip Manifold Assembly (Overspeed Protection): Electrical Trip Device Response Time*, was added to Section 2.3, Equipment Alerts.

July 2014. Interim revision. Clarification was provided to recommendations on electronic overspeed protection systems (Section 2.2.1.1).

January 2013. Changes include the following:

- Lubrication oil protection system and system components sections have been updated.
- Lube oil system schematic Figure 4 has been modified for clarification.
- Steam turbine lube oil system control and logic diagram has been updated.
- New recommendations have been added for monitoring bearing vibration protection.
- New recommendations have been added for managing the water quality and steam purity.
- Table 2, steam purity reference guide, has been added.

- Technical guidance and operating practices have been added for turbine casing drains, steam line drains and steam drain pots.

July 2011. This document has been completely rewritten.

April 2010. Minor editorial changes were done for this revision.

January 2005. Specific alerts (2.3) have been removed and a generic approach to alerts and their implementation has been added.

Section 2.2.2, Overspeed Trip and Section 2.2.3, Testing of Auxiliary and Emergency Lube Oil Systems have been revised to reflect the variety of systems found in industry.

January 2001. Recommendation 2.2.2, Overspeed Trip Tests, has been revised to incorporate the latest overspeed trip technology.

All information applicable to electric generators can be found in Data Sheet 5-12, *Electric AC Generators.*

Pertinent manufacturers' technical information is provided in section 2.3, Alert.

Revised October 1998

Revised August 1988

Revised October 1972

Original May 1968

APPENDIX C SUPPLEMENTAL INFORMATION

A steam turbine is a mechanical device that extracts thermal energy from highly pressurized steam and coverts it into rotary motion. The turbine derives much improvement in thermodynamic energy from the use of multiple stages in the expansion of the steam. The steam expands through a series of stationary and rotating blade sets, optimizing turbine efficiency. As the steam flows and expands through the turbine, its pressure falls and exhausts from steam high pressure to condenser/process low pressure.

Steam is supplied to turbines from different sources, such as boilers, heat recovery steam generators (HRSG), waste heat recovery boilers, along with fuel-fired boilers burning gas, coal, waste materials. Steam can also be supplied from steam headers and other steam supply or extraction lines.

In utility and power generation industries steam usually is produced in the boiler/steam generator section and collects in a steam drum. The steam then passes through a superheater section where it gains additional temperature. Steam is then conveyed to the steam turbine through high-pressure piping to the turbine steam stop valve (emergency stop valve), and then the control throttle valve (governor valve).

C.1 Steam Turbine Types

Steam turbines can be classified by modular system, type, power output, and whether or not a reheat system is required. The steam admissions sections (HP, reheat, and LP) may consist of one or two building blocks, and may be housed in one or more casings. There is single-flow, double-flow, and triple-flow admissions (see Figure C-1).

Cross-compound steam turbines: A multi-cylinder steam-turbine arrangement in which several machines are connected in parallel to separate generators (see Figure C-1). In a cross-compound steam turbine the superheated steam enters the High Pressure stage, expanding through the rotor blades before exiting to the Intermediate Pressure stage, both turbine rotors being on the same drive shaft. This HP/IP turbine rotates at 3600rpm driving a 2 pole generator. The exiting steam now crosses over from the IP stage into the Low Pressure turbine, where it expands through the rotor blades, driving its own shaft and giving up the last of its energy before being drawn into the condenser. This LP turbine rotates at 1800 rpm driving a 4-pole generator.

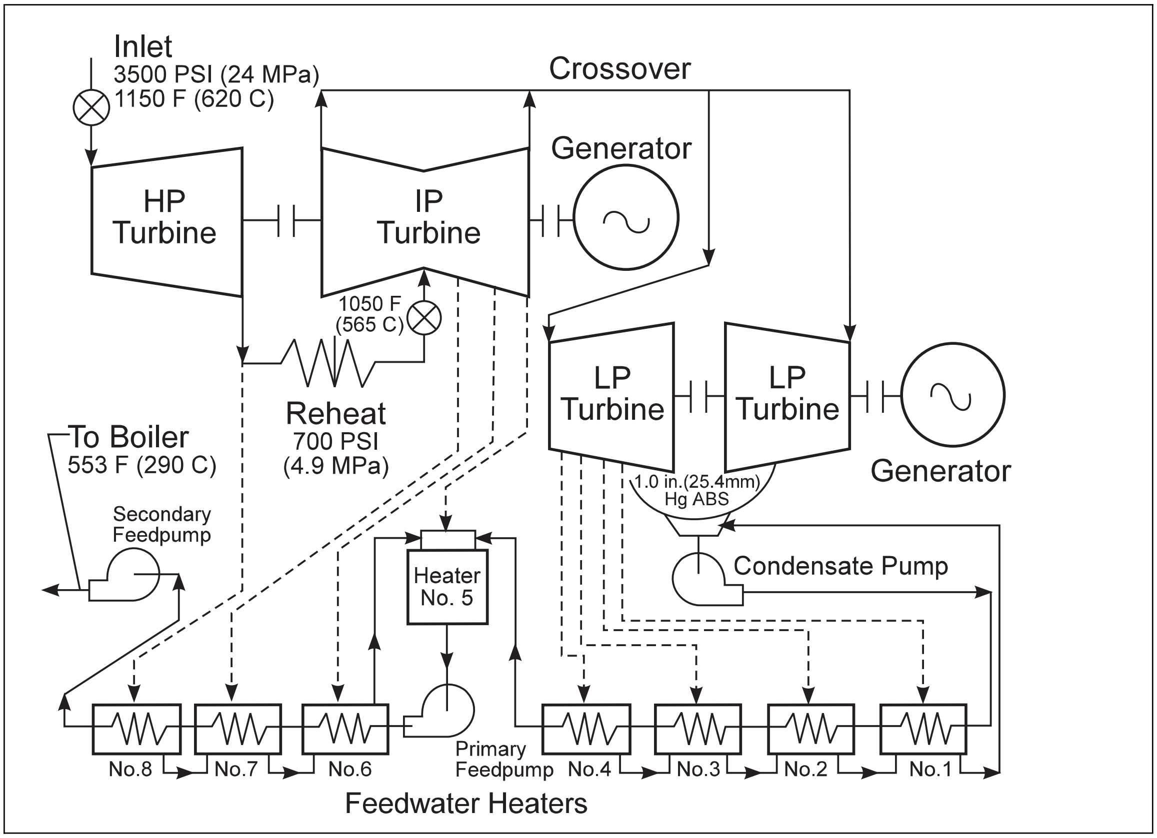

Fig. C-1. Utility steam turbine, cross-compound, reheat type, fossil and combined cycle application

Single shaft combined cycle steam turbines: Modern combined cycle power plants can have a steam turbine directly coupled to its own generator like in a conventional steam plant or the steam turbine can be part of a single shaft arrangement where the generator is in the middle, and the gas turbine is coupled on one end of the generator and the steam turbine is coupled to the other end of the same generator. For example For single shaft GE/Alstom KA24-1 Units, the GT24 gas turbine is rigidly coupled on the compressor end to the generator, The generator is in the middle and is coupled to the HP IP/LP steam turbine through a SSS clutch (AKA: Triple S clutch), and The HP VAX turbine is connected to the IP/LP steam turbine through a reduction gear box.

SSS clutch maintenance intervals: For single shaft combined cycle plants with the common arrangement to have the generator in the middle and use the SSS Clutch between the steam turbine and the generator, there is normally very little maintenance required to SSS clutches. A SSS Clutch inspection should occur approximately after 2000 starts plant starts (a cycle of one engagement and one disengagement). If a major plant inspection and overhaul occurs before 2000 plant starts have occurred (at a planned gas turbine hot gas path or major inspection), the owner might want to also inspect the clutch at that time. Typically, this inspection might be after 7-10 years of plant operation. The SSS Clutches are returned to the OEM's facility where they undergo a complete disassembly, visual inspection, thorough cleaning, and replace fasteners, pawls, pins, and springs. A report is prepared with inspection findings and they dynamically re-test the synchronizing mechanism, the pawl carrier, prior to clutch reassembly. This is normally accomplished within two weeks depending on workload at the OEM facility.

Types of steam turbines include the following:

- Reheat or non-reheat• Single casing or multiple casings
- Axial or radial
- Impulse or reaction
- Single stage or multistage

- Single or multi-valve inlet control
- Uncontrolled (non-automatic) or controlled (automatic) extraction
- Admission (induction)
- Condensing or backpressure (non-condensing

C.2 Steam Turbine Applications

Steam turbines are manufactured in a variety of sizes to drive generators for electric power and rotate mechanical equipment for various industrial applications. Steam turbine applications include the following:

- Electricity-generating station units (see Figure C.2-1): Generator-drive steam turbines coupled to electric generators at facilities whose principle function is to produce electric power for sale to private and commercial entities, including transmission and distribution companies
- Generator-drive steam turbines at industrial facilities (see Figure C-2-2): Steam turbines coupled to electric generators whose principal function is to produce electric power and/or thermal by-products (co-generation) to an adjacent host (or other entities)
- Mechanical-drive units: Steam turbines driving equipment other than generators, such as compressors, pumps, fans, and blowers.

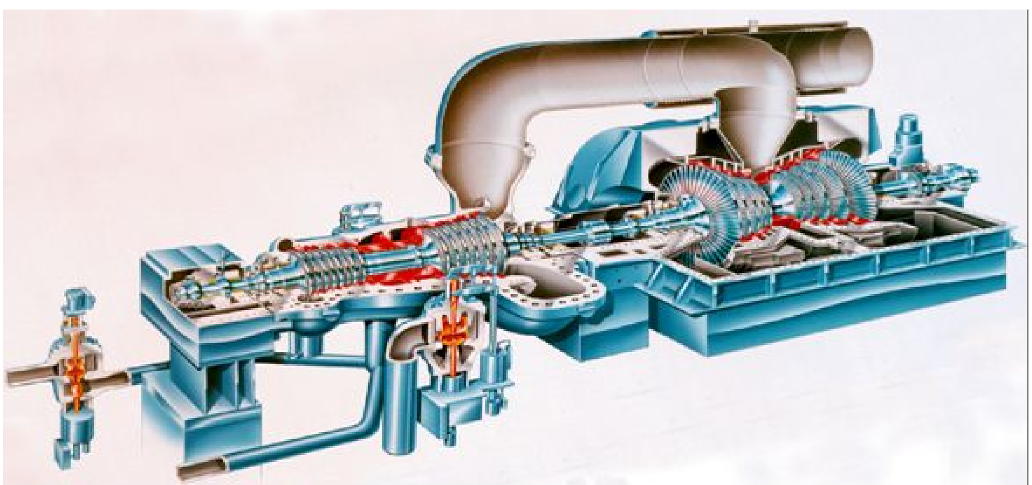

Fig. C.2-1. Generator-drive steam turbine with HP, reheat/IP and LP sections, down exhaust condensing, electric generating, combined cycle application (General Electric Company, all rights reserved, used with permission)

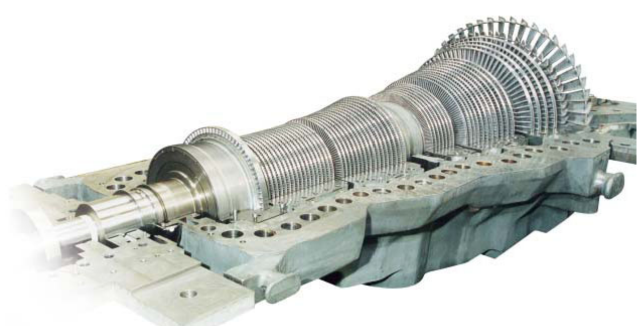

Fig. C.2-2. Generator-drive steam turbines at industrial facilities - rotor assembly with lower case (General Electric Company, all rights reserved, used with permission)

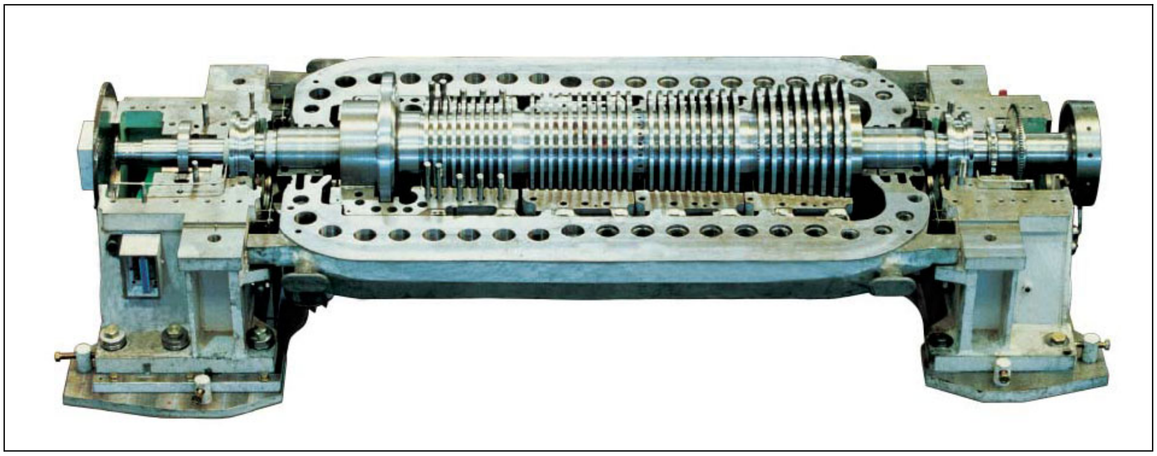

Fig. C.2-3. Mechanical drive steam turbine with impulse and reaction blades (General Electric Company, all rights reserved, used with permission)

C.3 Mechanical-Drive Steam Turbines

Mechanical-drive steam turbines drive equipment other than generators, such as compressors, pumps, fans, and blowers. They are used in various industries, such as oil and gas, pulp and paper, chemical, food processing and pharmaceutical plants.

Mechanical-drive steam turbines are also used in utility power stations. To drive feedwater pumps and frequently forced draft (FD) and induced draft (ID) fans. Small units are used to drive pumps, fans, and similar machines, often through reduction gears. These turbines can be either condensing or noncondensing, single-stage, or multiple-stage units. Mechanical-drive turbine operation, maintenance, inspection, and protection fall within the current industry requirement for all turbines. In general, they should be treated as all other turbines.

In most mechanical-drive turbines and where reduction gears are involved the turbine is usually connected to its driven unit by a flex coupling. These couplings permit certain desirable axial movement of the driven shaft. In the medium to large turbine units, the flexible couplings are usually gear-type and are enclosed in the same housing with the turbine and driven-unit bearings. All are lubricated by oil from a lube oil main circulation system.

A typical independent lubrication system consists of oil reservoir, pumps, coolers, filters, and pressure controls and piping. Two pumps are used for service, one is a mechanical shaft driven pump, and the other is a turbine driven pump (auxiliary pump), which is used at startup.

The governor control system regulates steam flow to the turbine, and it maintains the turbine's speed. The most common throttles used in older units are a fly-ball with weight pivots. The weight pivots will move outward from their normal position as turbine speed increases and engage a trigger to linkage that operates a trip, and that action closes the steam admission valves.

Another speed governor type is the hydraulic governor system that employs high-pressure trip oil to close the steam valve. Unfortunately, these mechanical systems are not provided with a redundant backup emergency system. Also, with age theses system become more difficult and costly to maintain and are often incapable of performing advanced functions to improve efficiency, reliability, safety protection, and to prevent losses.

C.4 Steam Turbine Structure and Components

Steam turbines may be constructed with one or more separate casings (cylinders). The larger generating station units may have three or four separate cylinders (turbines), one each for the high-pressure (HP) section, the intermediate-pressure (IP) section, and one or two low-pressure (LP) sections. Steam is piped from the exhaust of the HP cylinder to the boiler reheat section and from there to the inlet to the IP cylinder. Discharge from the IP cylinder is piped to the LP cylinders via crossover pipes. Turbine components include the following:

- Turbine casings (cylinders) or shells

- Turbine valves, steam admission valves
- Turbine steam piping
- Turbine rotors
- Turbine rotor disks
- Rotor rotating blades
- Stationary blades, nozzle diaphragms
- Turbine bearings
- Turbine seals, packing seals
- Turbine steam drainpipes
- Turning or jacking gear