FM Global
Property Loss Prevention Data Sheets **7-109**

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FUEL FIRED THERMAL ELECTRIC POWER GENERATION FACILITIES

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1.0 SCOPE

This data sheet provides property loss prevention recommendations for common processes and procedures, balance of plant systems, and operation and maintenance activities applicable to conventional steam cycle and combined cycle power generation facilities.

1.1 Changes

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

A. Added starting permissives associated with the DC lube oil pump.

B. Added Data Sheet 5-28, *DC Battery Systems*, to Section 4.0, References.

C. Added definitions of combined cycle power plant and single shaft combined cycle power plant to Appendix A, Glossary of Terms.

D. Added a definition of interlock and startup permissive to Appendix A.

1.2 Superseded Information

This data sheet supersedes Data Sheet 5-15/13-14, *Electric Generating Stations* and Data Sheet 11-1, *Electric Power Generation-Steam Cycle.* Data sheets 5-15/13-14 and 11-1 were retired.

2.0 LOSS PREVENTION RECOMMENDATIONS

2.1 Introduction

Refer to equipment-specific data sheets for recommendations pertaining to equipment not covered in this document.

Use FM Approved equipment, materials, and services whenever they are applicable. For a list of products and services that are FM Approved, see the *Approval Guide,* an online resource of FM Approvals.

2.2 Construction and Location

2.2.1 Locate and construct power generation facility control and DCS rooms so the contents of the rooms are protected from fires and equipment failures. Refer to the following data sheets for specific recommendations:

- Data Sheet 5-32, *Data Centers and Related Facilities*
- Data Sheet 7-101, *Fire Protection for* Steam Turbines and Electric Generators
- Data Sheet 7-79, *Fire Protection for Gas Turbines and Electric Generators*

2.3 Occupancy

Power generation facilities have changed significantly since they were first produced. Due to the harsh operating conditions, different materials have been phased in and out of use. Proper planning is needed to build and modify facilities to limit their exposure to hazards.

2.3.1 Coal handling and pulverizing produces dust. Maintain high standards of housekeeping, especially in the fuel-handling, preparation, and feed system areas of the power plant to minimize coal dust accumulation and the potential for a coal dust explosion. Refer to the following data sheets for specific recommendations:

- Data Sheet 6-2, *Pulverized Coal-Fired Boilers*
- Data Sheet 7-11, *Conveyors*
- Data Sheet 7-73, *Dust Collectors and Collection Systems*
- Data Sheet 7-76, *Prevention and Mitigation of Combustible Dust Explosions and Fires*
- Data Sheet 8-10, *Coal and Charcoal Storage*

2.3.2 Power generation facilities constructed prior to the mid-1970s may have transformers and/or oil-filled circuit breakers that use (or originally used) insulating oils containing PCBs. If these are found, follow the recommendations in Data Sheet 5-4, *Transformers.*

2.4 Protection

2.4.1 Provide fire protection for select power generation facility areas so the contents of the areas are protected from fires and equipment failures. Provide protection in accordance with the applicable data sheets listed in Section 4.1 and/or other equipment-specific data sheets.

2.5 Equipment and Processes

2.5.1 Safety System Logic

2.5.1.1 Provide safety system logic in accordance with the applicable equipment-specific FM Global data sheets or other appropriate codes and standards (e.g., NFPA, ASME, IEEE).

2.5.2 Alarms, Interlocks and Startup Permissives

2.5.2.1 Establish practices for alarm management in accordance with Data Sheet 10-8, *Operators.*

2.5.2.2 Provide permissive interlocks as needed to ensure correct procedures are conducted during equipment/plant operations.

2.5.2.3 Provide tripping interlocks to either automatically remove equipment from operation or cause equipment runback where operating parameters are beyond the range dictated for proper operation.

2.5.2.4 Where practical, provide an alarm to alert operators to an impending trip condition.

2.5.2.5 Provide first-out indication for all tripping interlocks.

2.5.2.6 For electric generator drive gas and steam turbines, install a startup permissive to prevent startup when the emergency DC lube oil pump (ELOP) is inoperable. The startup permissive should protect against the following conditions:

1. DC power supply low voltage
2. ELOP low discharge pressure
3. ELOP breaker not in the “Auto” position

Reference Appendix A, Glossary of Terms for a definition of Interlock and Startup Permissive.

2.6 Operation and Maintenance

2.6.1 Safety Controls

Prior to deregulation in the power generation industry, control and safety logic served as a backup to plant operators. Today, however, there may be only one or two operators in the control room, making logic systems more critical in protecting the unit. Functional testing helps ensure the logic is able to perform as intended.

2.6.1.1 Functionally test each safety system at the time of installation, on an annual basis, any time maintenance work is done to the safety system, and following upgrades or changes to the safety system. Create actual trip conditions to the extent safely practical when conducting functional tests.

Many safety devices are referred to in equipment-specific data sheets. In addition, the overall functionality testing program may include, but is not limited to, the following safety devices:

- Deaerator tank level controls (to produce feed-pump trip)
- Air preheater sensors (pressure and temperature differentials)
- Automatic startup of critical redundant pump systems in case of trip of running pumps
- Boiler feedwater
- Condensate

- Seal oil
- Control oil
- Lube oil
- Hydrogen or other generator cooling medium
- Fuel train
- Chemical feed system
- Condenser cooling system
- Pulverizer system
- Power augmentation
- NO_x reduction systems
- DCS system

2.6.2 Maintenance

See Data Sheet 9-0, *Asset Integrity*, for general maintenance recommendations, and the applicable equipment-specific data sheet for more detailed recommendations.

2.6.2.1 Develop and implement a plant-specific maintenance program, and keep it updated on all main and auxiliary equipment. Where necessary, overhaul all equipment in conjunction with planned outages of the boiler, turbine, and generator.

2.6.2.2 Evaluate the plant processes and procedures based on physical and operational changes that have occurred during the lifecycle of the plant.

2.6.2.3 Attemperators (also known as “desuperheaters,” depending on their function) can be found in various piping systems within the power generation facility (internal and external to the boiler). Include attemperators in the plant inspection and maintenance plan. Include the following items:

A. Evaluate the integrity of the attemperator components.

B. Ensure high/low-temperature alarms are in place to monitor attemperator function.

C. Verify adequate drainage is supplied downstream of the attemperator to remove excess water within the system from spraying operations.

2.6.3 Process Fluids

The process fluids of the facility present potential sources of contamination that may introduce a hazard and/or have a negative effect on the condition of the systems, equipment, and components. Contamination may be the result of failure within heat exchangers, filters with poor performance, or locations in which chemicals are added into the system.

2.6.3.1 Evaluate the possible sources and likely extent of any potential contamination during all foreseeable modes of standard and emergency operation (startup, shutdown, load following, etc.).

2.6.4 Operating Regime

Many units that were originally designed to operate in a baseload capacity are now subject to flexible cyclical service. This includes reducing minimum load availability, load following with large demand swings, and an increase in the number of hot, warm, and cold starts. These types of service changes may require design changes to the unit.

2.6.4.1 Ensure unit operation is consistent with OEM guidelines, the following data sheets, and subsequent recommendations in this section:

- Data Sheet 5-4, *Transformers,* Section 2.1.5
- Data Sheet 5-12, *Electric AC Generators,* Section 2.3
- Data Sheet 6-23, *Watertube Boilers,* Section 2.2.7, Boiler Operation

- Data Sheet 13-3, *Steam Turbines,* Section 2.2.10, Steam Turbine Operation
- Data Sheet 13-17, *Gas Turbines,* Section 2.3.1, Operations

2.6.4.2 Adjust inspection and maintenance intervals in order to identify deterioration associated with the service conditions. This is particularly important at plants originally designed for baseload operation that will be operated (or currently operate) in flexible cycling service.

2.6.4.2.1 Provide additional monitoring of plant equipment or components as necessary to identify potential deterioration.

2.6.4.3 When changes in the low-load limits of a unit are implemented, evaluate the dew point temperatures of the flue gas to determine the risk of increased corrosion in the backpass and exhaust system of the boiler.

2.6.4.4 When startup and shutdown times are modified, ensure ramp rates are sufficiently low to limit stress within materials from increased thermal gradients. Monitor steam and metal temperature variations and keep them within manufacturer recommendations.

2.6.4.5 Ensure pumps and motors operate within their designed ranges.

2.6.4.6 Evaluate the water treatment system to ensure it is adequately designed to provide the required purity of water given the most extreme of the anticipated transient water flow conditions.

2.6.4.7 Implement layup procedures in accordance with Section 2.6.6 of this document.

2.6.5 Plant Retrofits

Plant retrofits have become more common due to several environmental and economic factors. The goal of the retrofits may be to convert to another fuel source, add emissions control equipment, or retire some part the facility. A fuel retrofit (e.g., fuel oil or coal to natural gas) can be accomplished in various ways. A plant may choose to perform a full conversion to natural gas fuel on the existing boilers, a conversion with co-firing with natural gas fuel using the existing boilers, or replace the existing boilers with natural gas-fired boilers to power the existing steam turbines.

2.6.5.1 Perform a site-specific engineering study to determine and evaluate the performance implications and overall feasibility. At a minimum, evaluate the following conditions:

A. Modification or replacement of flue gas, draft air, recirculating air and primary air fans

B. Change in need for soot blowing, steam attemperation, air preheating, flue gas desulfurization, flue gas fan use

C. Layup (“mothballing”) of non-used components

D. Change in auxiliary electric load due to the removal of equipment from service (coal handling/processing, primary air fans)

E. Addition of natural gas supply lines within the plant

F. Alteration/replacement and change in operating conditions of burners, heat transfer surface within the boiler, balance of plant equipment (heat rejection/transfer), combustion control system, burner management system

G. Modification of maintenance activities

H. Inherent project risk for utilization of a hybrid unit

I. Steam turbine changes (higher back-end load with HRSG)

2.6.5.2 When considering adding emissions controls to an existing unit, evaluate the potential impact to the sizing or need for flue gas fans, duct and boiler stiffening, maintenance activities, and increase on auxiliary electric loads. Also, adhere to the recommendations in Data Sheet 6-6, *Boiler-Furnace Implosions.*

2.6.5.3 Layup of entire facility for an extended amount of time (also known as “mothballing”) may be the best choice for the plant. See the recommendations for layup procedures in Section 2.6.6 of this document.

2.6.6 Layup Procedures

The amount of time for which a unit or a piece of equipment is shut down is fundamental to the type of layup strategy selected. Layup strategies should take into account site-specific factors, operational requirements, and unit design. Ensuring a seamless transition between operation, shutdown, the layup period, unit startup and the unit's return to service should be factored into the strategy. Adequate storage of the critical components and systems should be incorporated into a comprehensive layup procedure. The strategies used should be specific to the equipment affected.

2.6.1.1 Layup equipment as necessary between operational cycles. Layup type should be in accordance with intended duration of layup.

2.6.1.1.1 If intended duration of layup changes, the layup type provided should be reevaluated and modified as necessary.

2.6.6.2 Ensure operations and maintenance staff are familiar with the layup equipment and trained in how it should be operated and maintained to support effective layup of the unit.

2.6.6.3 Ensure necessary testing and inspections to keep the unit available are continued during the layup period. The scope of the testing/inspections may include fire protection systems and energized systems and equipment that is expected to operate during the layup period (such as turning gear and lubrication oil systems to allow for routine rotation of the turbine generator shafts).

2.6.6.4 At the conclusion of the layup period, ensure proper equipment testing is performed as a part of the startup sequence. If testing of systems and components is not possible during the layup period due to the layup configuration, or testing is discontinued based on a risk analysis, testing beyond what was originally planned may be required before placing the equipment into service.

2.7 Training

General recommendations on training operators and maintenance personnel are provided in Data Sheets 10-8, *Operators,* and 9-0, *Asset Integrity*.

2.8 Human Factor

See recommendations for incident investigations and shift changes in Data Sheet 10-8, *Operators.*

2.8.1 Written Procedures

Written Procedures are paramount to the proper operation and maintenance of the facility.

2.8.1.1 Maintain written procedures that detail the current anticipated operating regimes readily available for use by the operators.

2.8.1.2 In addition to standard operating procedures, provide the following written procedures and others, as applicable:

- Low pressure, loss of turbine lube oil
- Low pressure, loss of generator seal oil
- High bearing metal temperature
- High lube oil temperature
- Low lube oil tank level
- High/low boiler water level
- High feedwater heater water level
- Loss of condenser vacuum
- Chemical excursion
- Loss Of DC or control power
- High exhaust gas spread

- Generator motoring
- High vibration or thrust
- Valve closure failure

2.8.1.2.1 Implement procedures that control critical valves and switches that could result in equipment breakdown if erroneously manipulated.

- Document all critical valves and switches and their locations
- Document the SAFE position (open or closed)

2.8.2 Emergency Response and Pre-Incident Planning

Because of the small number of personnel available during many operating hours, cooperation with outside assistance is an important part of any emergency plan. A facility emergency response team should be thoroughly organized, trained, and drilled at close periodic intervals.

2.8.2.1 Design an emergency response plan to address potential worst-case scenarios. Refer to Data Sheet 10-1, *Pre-Incident and Emergency Response Planning.*

2.8.3 Outage Management

Outages are regular occurrences at power generation facilities. During outages, activities are performed that give personnel who are not direct members of the organization (e.g., contractors and their subcontractors, regulatory bodies, the public fire service) access to and control over critical areas and assets.

2.8.3.1 Develop programs and procedures for selecting and managing contracted service. Refer to Data Sheet 10-4, *Contractor Management.*

2.8.3.1.1 Consider the breadth of available services, relationship potential, and company stability during the contractor selection process. These factors may come into play if unsuspected conditions occur during the outage.

2.8.3.1.2 Provide contractors with a detailed scope of work and list of acceptance criteria for each facet of each project.

A. Establish acceptance criteria at several pre-determined hold points throughout a process and include final acceptance criteria prior to putting a part or piece of equipment into service.

B. Require adequate proof of satisfactory completion of acceptance criteria from the Contractor.

C. Where necessary, provide additional QA/QC, independent of the contractor's internal QA/QC program, in order to ensure acceptance criteria is met.

2.8.3.1.3 Review contractor task performance training, proficiency demonstrations, procedures, and other qualifications for applicability to the specific need as outlined in the scope of work. These tasks can include, but are not limited to, the following:

- Rigging
- Heavy equipment operation
- Non-destructive examinations
- Welding, electrical work
- Engineering design/analysis
- Erection of scaffolding
- Managing the foreign material exclusion process (Data Sheet 9-0, *Asset Integrity*, Appendix D)

2.8.3.2 Ensure plant facilities and assets remain secure throughout the outage. Regulate contracted personnel to their necessary work areas.

A. If contracted personnel require access to critical assets and/or areas, properly vet personnel prior to giving them access and/or supervise them while they have access.

B. Admit only authorized personnel to the control room and computer room and keep these areas secure if not constantly attended.

2.8.3.3 Require adequate proof of contractors returning equipment to a satisfactory operational state after project completion.

2.8.3.3.1 Implement sufficient checks and balances to prevent defective equipment from being returned to service or foreign material from being introduced to systems.

2.8.3.4 Provide a system that ensures uncompleted action items are carried over to the next outage, and any additional changes to maintenance or operating functions are made as a result.

2.8.4 Labeling Equipment

Labeling equipment is a way to assist plant personnel in identifying critical components. Labeling may include acronyms, words, symbols, and color patterns. Clear labeling and/or color-coding assists in reducing the risk of operating incorrect valves, switches, etc.

2.8.4.1 Position labels so they are clearly visible from normal working positions under normal working conditions. Consider contrast, size, and content when designing labels.

2.8.4.2 Affix labels so they do not become blocked by any adjacent or protective equipment.

2.8.4.3 Follow local reading customs when orientating the labels. Affix labels horizontally whenever possible and ensure their wording is unambiguous.

2.8.4.4 Establish label conventions and document them in procedures. Include how to identify and replace broken or missing labels as well as any special labeling material conformance (e.g., temperature/environment affected areas).

2.8.4.5 Consider labeling the following components:

- Steam inerting system
- CO_2 purge system
- Fuel system
- Hydrogen system
- Lubricating/control oil system
- Steam lines
- Feedwater system
- Filters
- Heaters/heat exchangers
- Tanks
- Strainers
- Support components (hangers, snubbers, etc.)
- Gauges
- Protective covers
- Circuit breakers
- Valves

2.8.5 Ignition Source Control

Automatic fire protection for flue gas equipment, such as desulfurization and plastic-lined stacks, may not be practical due to the environment of the components.

2.8.5.1 Control ignition sources by implementing good human element programs. See Data Sheet 10-3, *Hot Work Management.*

2.8.5.2 Do not allow hot work to be performed on flue gas desulfurization units unless the slurry pump is available to be operated during the hot work.

2.9 Electrical

2.9.1 Ensure there is a reliable power supply for control systems in order to minimize the possibility of interruption of control and operation functions.

2.9.1.1 Ensure this power supply is completely independent of other safety power supply systems. Refer to Data Sheet 5-23, *Design and Protection for Emergency and Standby Power Systems.*

2.9.2 For safety logic employing an energize-to-trip design, ensure a reliable electrical supply by providing **all of** the following:

A. Redundant power supplies and/or an uninterruptible power supply (UPS) for the safety system logic.

B. Redundant, independent power to the power supplies and devices actuated by the safety system using independent power feeds, battery backup, and/or an emergency backup system providing an uninterrupted power supply (UPS).

C. Battery systems/UPS used for backup of the DCS system that are inspected and tested in accordance with Data Sheet 5-19, *Switchgear and Circuit Breakers, and Data Sheet 5-28, DC Battery Systems*.

3.0 SUPPORT FOR RECOMMENDATIONS

3.1 Loss History

3.1.1 Loss Statistics

The loss statistics in Tables 3.1.1-1 and 3.1.1-2 are based on FM Global loss data for fuel fired thermal power plants from 2005 to June 2015.

Table 3.1.1-1. Electric Power Generation Loss Experience by Cause, 2005 to 2015

Cause	*By Number of Losses*	*By Loss Cost*
Mechanical breakdown	54%	57%
Electrical breakdown	27%	23%
Fire	8%	6%
Explosion	1%	5%
Miscellaneous	4%	3%
Pressure equipment breakdown	2%	2%
Collapse	1%	1%
Escaped liquids	1%	1%
Impact	1%	1%
Wind and hail	1%	1%
Total	100%	100%

Table 3.1.1-2. Losses in Which Equipment was Identified, 2005-2015

Equipment	*By Number of Losses*	*By Loss Cost*
Turbine	46%	54%
Generator	23%	20%
Transformer	12%	10%
Boiler	3%	5%
Non-rotating electrical equipment	3%	2%
ACC	1%	2%
Cooling tower	1%	1%
FW pump	1%	1%
Other vessels	1%	1%
Blowers and fans	1%	1%
Conveyor	2%	1%
Misc.	6%	2%
Total	100%	100%

3.1.2 Illustrative Losses

Loss examples for specific equipment can be found in their respective data sheets. The loss examples provided here are related to balance of plant issues.

3.1.2.1 Increased Conductivity in Feedwater Causes Steam Turbine Blade Failure due to Stress Corrosion Cracking

This was a co-generation plant consisting of two HRSG units, each consisting of two combustion turbines and one steam turbine generators. The four combustion turbines (CT) were LM 6000 units. The two steam turbines were 27 MW Dresser Rand turbines. Each CT exhausted to a once-through heat recovery steam generator (HRSG), producing subcritical steam. This is relatively unusual as once-through boilers are typically used for supercritical steam.

The steam produced in the HRSG was used for driving the steam turbines, power augmentation in the CTs, and steam injection for lowering NO_x in the CTs.

The feedwater supply was provided by the city and was sent through a reverse osmosis (RO) system. After the RO system, the water was dumped into the cooling tower sump until the cation content got below 1000 ppb. During startup and shutdown, as a result of the salt content of the water, cation content stabilized from 1000 ppb to 160 ppb.

The operating regime of the units was changed from base loaded to cycling daily. Therefore, every morning the RO was started, the feedwater tank received excessive chlorides as the RO system stabilized. This was the source of excessive sodium in the system. Following the loss, metallurgical analysis found sodium deposits on the CT and the steam turbine blades.

Additionally, the facility had previously installed a batch injection system of ammonium hydroxide to the feedwater system for PH control. This likely overloaded the condensate polisher (overload of cations from excessive sodium salts and ammonia ions) and may have let some sodium ions slip through.

Because once-through boilers do not have steam drums and cannot be blown down when chlorides are high, it is possible for all chlorides, including sodium ions, to pass through the boiler and be deposited on the blading of the steam turbines and gas turbines. Both steam turbines and multiple gas turbines suffered from stress corrosion cracking. This caused turbine rotor removals, and the full inspection/removal of all diaphragms, water catchers, and rotor disks.

Following the losses, a demineralizer was installed downstream of the RO system. The chloride content downstream of the demineralizer changed to 6-7 ppb, which is acceptable for feedwater make-up tank. They also added steam purity monitoring and an alarm on the conductivity meter to indicate high conductivity. A thorough assessment of the water treatment system during the operating regime change should have identified the excessive amount of chlorides.

3.1.2.2 Hot Work Fire in Flue Gas Absorber

This was a 517 MW pulverized coal-fired unit. Coal containing sulfur was the primary fuel. Burning sulfur produces sulfur dioxide (SO_2) as one of the byproducts of combustion that needs to be removed from the flue gas before it is released to the atmosphere to prevent pollution. After the fuel is burned, the boiler flue gasses pass through electrostatic precipitators and then to absorbers through steel ducts that enter the bottom of the absorber.

During operation, the absorber works in essentially inert condition as the exhaust gas contains little oxygen. During outages, the absorber would be full of air, eliminating the inert conditions. The steel ducts had leakage occurring at the top of the unit (30 ft [9 m] above the demister trays), which was to be repaired during the outage.

A cutting torch used in the leak repair process created sparks. The hot sparks ignited the plastic demister nozzles and fire spread to slurry trays, mist eliminators, and slurry piping below. Due to the enclosed construction of the absorber, it was difficult to get suppression efforts to the fire. The slurry pumps were turned on in an attempt to control the fire. The slurry pumps controlled the remaining fire, but severe damage had already occurred.

The internal steel supporting structure collapsed and piled on the bottom of the unit. The glass mat of the FRP slurry piping could be seen, as well as fallen ceramic wall tiles. The stainless-steel dome of the absorber was also warped and required repair.

3.1.2.3 Fuel Gas Explosion in Air-Cooled Condenser (ACC)

A 245 MW co-generation plant consisted of a single combustion turbine (CT), a three-stage heat recovery steam generator (HRSG), a steam turbine with HP and LP turbine sections, and an air-cooled condenser (ACC). The bleed steam from the HP exhaust end was sold to an adjacent chemical plant.

The fuel gas grid pressure of 375 psig (26 bar) was boosted to 500 psig (34.5 bar) by onsite gas compressors. The compressed fuel gas was steam pre-heated by an HP and an LP shell and tube-type fixed plate heat exchanger arranged in series. Pre-heating of the fuel gas increased combustion efficiency of the CT. Condensate from the heat exchanger drained to the main condensate tank. Non-condensable gases from the condensate tank were removed by vacuum pumps during normal operation.

The fuel gas heater skid was provided with motor-operated and manually operated isolation valves that were all closed for a major outage. Two days into the outage, hot work performed on the ACC to replace a 1 in. (25 mm) condensate pipe. A hot work permit was issued, however, there was an explosion in the ACC during the hot work which caused significant damage. In addition to the damage to the ACC, the force of the explosion caused one of the relief valves on the LP turbine casing to open.

The plant had a history of leakage in the LP fuel gas heater and it was replaced two years before the incident. No NDE had been performed on the HP fuel gas heater for over 10 years prior to its replacement. Subsequent to the loss the HP fuel gas heater was found to have leakage.

The HP heater was cracked which allowed fuel gas onto the condensate side of the heat exchanger. High pressure fuel gas traveled through the condensate line into the ACC, likely during operation or shutdown. Air infiltrated the ACC during the outage and put the atmosphere in explosive range. Damage was revealed on the ACC structure and interior bracing, all four ACC steam risers, ACC lower headers, and ACC finned tube bundles. Damage was also revealed on controls, valves instruments, etc. from debris. Finally, damage was revealed at the steam turbine enclosure adjacent to the steam turbine relief assembly (which released pressure during the event).

Following the explosion, the plant rerouted the fuel gas heater condensate line to waste through a knockout drum and provided an LEL detector in the drum vent.

3.1.2.4 Boiler Dry Firing

The boiler was a 1969 coal-fired unit with a steaming capacity of 1,180,000 lb/hr (149 kg/s), 1,875 psi (129 bar), 1005°F (540°C). The boiler-turbine-generator unit produced 170 MW of power. This unit normally operated base loaded (8000 hr/yr). The unit had semi-automatic controls because of the large drum fluctuations (water temperature and pressure). The unit had recently replaced the radiant superheat pendants, and waterwall tubes had been measured for remaining wall thickness for future reference. Sample tubes were also taken for analysis.

During operation, a faulty deaerator level transmitter simultaneously sent erroneous signals to the deaerator level indicator in the control room and to the deaerator regulator, preventing the condensate pumps from refilling the deaerator storage tank. The feedwater pumps lost suction, preventing water from going to the steam drum to maintain level. The unit operator, unaware of the true deaerator level, attempted to maintain boiler drum pressure by rapidly reducing load. The loss of drum level led to a loss of water circulation in the boiler's waterwall tubes, resulting in overheating, rupture, and distortion of the furnace waterwalls. Lack of a low water trip on the boiler contributed to the loss.

Cause of the level transmitter malfunction was particulate matter trapped in the pneumatic transmitter nozzle(s). The particulate matter was rust particles that formed from excess moisture in the air system. Instrument air dryers were being drained twice per shift and were not drying the air sufficiently.

3.1.2.5 Water Hammer in Steam Pipe

A single steam turbine generator produced 626 MVA. The steam was produced in a single coal fired boiler built in 1980. The Turbine had high pressure (HP), intermediate pressure (IP) and two coupled low pressure (LP) turbines. The main steam line was 25 in. (63.5 cm) in diameter (supply for HP turbine), the cold reheat line was 36 in. (91.4 cm) in diameter (HP exhaust return to boiler) and the hot reheat line was 42 in. (106.7 cm) in diameter (supply for IP turbine). The IP turbine exhausted directly to the LP turbine.

A check valve was added to the CRH line in the 1990s to prevent turbine blades from overheating due to windage. This check valve was installed at the bottom of the vertical run of the CRH line just below the attemperator spray connection. A high-energy piping inspection program, including hanger inspection, was in place. Drains were regularly checked for proper operation and all critical control valves were included in a maintenance program.

The loss occurred during the startup of the unit. Water that had accumulated in the vertical section of the CRH piping (above the check valve) started to flash to steam when the throttle valves were opened. This steam drove the water above the check valve up the vertical section of the CRH pipe, impacting the elbow at the top. The water hammer event caused the CRH line to shift vertically upward 5 ft (1.5 m), breaking most of the hanger supports and associated building steel (levels 2-12). This caused the pipe to fall 7 ft (2.1 m) below its original position, having the bottom elbow rest on the concrete floor of the building's second level. The source of the water was most likely from the valves associated in the attemperator spray feed line.

Approximately 280 ft (85.3 m) of CRH piping moved during this incident. No piping ruptured due to overpressure. However, due to the stresses imposed on the section of piping, the upper and lower elbows were replaced and nondestructive testing of the remaining piping welds and highly stressed areas were inspected.

3.1.2.6 Loss of Lubrication Oil

While at full load operation, the DC power supply of a gas turbine generator unit was interrupted by an operator who erroneously isolated the two independent DC power supplies to a single DC bus bar. As a result of the loss of DC power, the unit tripped.

The DC bus, however, not only provided power for the unit control systems, but also tripping current for the generator circuit breaker, the controls of the AC power-driven main/auxiliary lube oil pumps, and the emergency DC power lube oil pump

As a result of the electrical configuration, as the unit tripped, the electrical power supply to all three lube oil pumps, both DC and AC powered, was lost and the bearings were starved of oil. To make things worse, the generator breaker could not open due to the lost DC power supply. As the generator remained connected to the grid following the trip, it acted as a motor driving the turbine and kept rotating at the grid frequency for minutes until the erroneous switching operation was recognized. The DC supply was restored, allowing the generator breaker to open, and the rotor stopped almost instantaneously.

The resulting damage extended far beyond the bearings on this unit, requiring a full re-blading of the turbine. In addition, due to the loss of seal oil, the hydrogen concentration in the generator dropped and ignited, resulting in damage to the generator windings.

Following the loss, the configuration of the electrical system was evaluated to eliminate single-point failures. Also, human element programs were improved through training and strengthening enforcement, including lock out/tag out, management of change and switching procedures, and operator training.

3.1.2.7 Generator Thermal Failure

A 340 MW unit with a water-cooled stator experienced complete thermal failure of the stator insulation when several modules in the DCS stopped functioning and turned off the stator cooling water pump. The controls were designed to alarm and automatically run back to a lower load upon loss of the pump, but this run-back feature was not function-tested after a DCS conversion, and had not been properly transitioned. Furthermore, the stator water temperature trip for this unit had been bypassed in the DCS logic at some prior time and, without function testing, this error remained undetected until after the loss. By the time the operator got the unit offline, the stator insulation was already ruined. A full re-wind of the generator was required, making the unit unavailable for three peak summer months.

4.0 REFERENCES

4.1 FM Global

Data Sheet 5-4, *Transformers*
Data Sheet 5-12, *Electric AC Generators*
Data Sheet 5-19, *Switchgear and Circuit Breakers*
Data Sheet 5-23, *Design and Protection for Emergency and Standby Power Systems*
Data Sheet 5-28, *DC Battery Systems*
Data Sheet 5-32, *Data Centers and Related Facilities*
Data Sheet 6-2, *Pulverized Coal-Fired Boilers*
Data Sheet 6-23, *Watertube Boilers*
Data Sheet 7-11, *Conveyors*
Data Sheet 7-45, *Safety Controls, Alarms, and Interlocks (SCAI)*
Data Sheet 7-73, *Dust Collectors and Collection Systems*
Data Sheet 7-76, *Prevention and Mitigation of Combustible Dust Explosion and Fires*
Data Sheet 7-79, *Fire Protection for Gas Turbines and Electric Generators*
Data Sheet 7-101, *Fire Protection for Steam Turbines and Electric Generators*
Data Sheet 8-10, *Coal and Charcoal Storage*
Data Sheet 9-0, *Asset Integrity*
Data Sheet 10-4, *Contractor Management*
Data Sheet 10-8, *Operators*
Data Sheet 13-3, *Steam Turbines*
Data Sheet 13-17, *Gas Turbines*

Understanding the Hazard: *Lube-Oil Testing* (P0219)
Understanding the Hazard: *Boiler Feedwater Treatment* (P0196)
Understanding the Hazard: *Outages at Power Generation Facilities* (P15110)
Understanding the Hazard: *Circuit Breaker Functional Testing* (P0183)
Understanding the Hazard: *Lack of Electrical Testing of Motors* (P0186)
Understanding the Hazard: *Deaerator Vessel Weld Cracking* (P0269)
Understanding the Hazard: *Fan and Blower Failure* (P0372)
Understanding the Hazard: *High-Energy Pipe Failure* (P0362)
Understanding the Hazard: *Flexible Operations in Thermal Power Generation* (W333750)
Understanding the Hazard: *Power Generating Assets Due for Retirement* (W333404)

4.2 Other

American National Standards Institute (ANSI). ANSI/ISA-84.00.01, *Functional Safety: Safety Instrumented Systems for the Process Industry Sector.*

International Electrotechnical Commission (IEC). IEC 61508, *Functional Safety of Electrical/Electronic/Programmable Electronic Safety-Related Systems.*

International Electrotechnical Commission (IEC). IEC 61511, *Functional Safety: Safety Instrumented Systems for the Process Industry Sector.*

APPENDIX A GLOSSARY OF TERMS

Auctioneering system: A system in which multiple sensors are processed through a logic controller to ensure a reliable reading. All sensors perform identical functions and their outputs are compared by the logic controller. The majority is established and a single fault will not interrupt normal operation. Also known as a “voting” system.

Brayton cycle: An ideal thermodynamic cycle describing the working of a constant pressure heat engine. The cycle consist of isentropic compression (ambient air in the compressor), isobaric heating (fuel addition in the combustor), isentropic expansion (energy transfer in the turbine), and isobaric heat rejection (exhaust).

Combined Cycle Power Plant (CCPP): The term combined cycle refers to the two thermodynamic cycles, the Brayton gas turbine (GT) cycle and the Rankine steam turbine (ST) cycle, that are combined for maximum efficiency. Gas or liquid fuel is burned in the GT spinning a generator producing electricity. The high temperature GT exhaust that would normally be lost to the stack, is redirected to a heat recovery steam generator (HRSG) creating superheated high-pressure steam. This steam is directed to a ST which spins a second generator producing approximately 50% additional electricity. In a conventional 1X1, 2X1, or 3X1 CCPP, each GT has its own associated HRSG supplying steam to one or more steam turbines. For example, a 2x1 CCPP has two GT/HRSG trains supplying steam to one steam turbine. Another CCPP configuration is the single shaft, combined cycle power plant (SSCC). The single shaft unit arrangement typically consists of a GT directly coupled to a generator on one end and on the other end, a steam turbine connected to the same generator by a self-synchronizing clutch (SSS Clutch) with all three on one single shaft (GT+Gen+ST). An SSCC steam turbine valve deficiency can lead to ST overspeed and damage to all equipment connected on the common shaft (GT+Gen+ST).

Fail-safe: The capability to go to a predetermined safe state in the event of a specific malfunction.

FM Approved: A product or service that has satisfied the criteria for Approval by FM Approvals. Refer to the *Approval Guide* for a complete list of products and services that are FM Approved.

Interlock: A powerplant interlock is a safety mechanism that prevents equipment from operating under unsafe conditions or in a way that could cause damage to the equipment or to the plant. Interlocks are designed to prevent unintended or accidental operations, and they are typically used to ensure that equipment is properly aligned, that all safety systems are functioning properly, and that adequate power, fuel, or other resources are available for the equipment to operate safely. Interlocks may be mechanical or electrical in nature, and they are often integrated into other control systems or safety systems within the plant. The purpose of interlocks is to help ensure the safe and reliable operation of the powerplant.

Process fluid: Fluids required to run a facility. Examples include fuel supply, air supply (draft and instrumentation), water, and steam.

Rankine cycle: An ideal thermodynamic cycle consisting of heat addition at constant pressure (approximated in the steam generator), isentropic expansion (approximated in the steam turbine), heat rejection at constant pressure (condenser), and isentropic compression (approximated in the condensate and boiler feed pumps).

Startup Permissive: A powerplant start up permissive is a set of conditions that must be met before a powerplant can be started. These conditions may include things like verifying that all safety systems are functioning properly, ensuring that fuel and other supplies are available, and confirming that the plant is in a safe operating state. Startup permissives are designed to help ensure that the plant can be started safely and reliably and to minimize the risk of accidents or equipment damage. Some examples of power plant startup permissives are turbine lube oil is on, turbine turning gear is on, condenser vacuum is established, generator breaker is open, master protective trips are reset, generator field excitation voltage breaker is open, fire protection system is enabled, emergency oil pump breaker is in Auto, turbine drains are open, steam turbine gland steam sealing is on, boiler water drum levels are correct, etc.

Thermal power station: A power plant in which heat energy is converted to electric power.

APPENDIX B DOCUMENT REVISION HISTORY

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

A. Added starting permissives associated with the DC lube oil pump.

B. Added Data Sheet 5-28, *DC Battery Systems*, to Section 4.0, References.

C. Added definitions of combined cycle power plant and single shaft combined cycle power plant to Appendix A, Glossary of Terms.

D. Added a definition of interlock and startup permissive to Appendix A.

January 2017. This data sheet has been completely revised. The following major changes were made:

A. Changed the number and title from 11-1, *Electric Power GenerationSteam Cycle,* to 7-109, *Fuel Fired Thermal Electric Power Generation Facilities.*

B. Changed the document from an 11-series (Systems, Instrumentation, and Control category) data sheet to a 7-series (Hazard category) data sheet.

C. Relocated the relevant recommendations from DS 5-15/13-14, *Electric Generating Stations,* to this data sheet.

D. Deleted support material that did not enhance understanding of the recommendations.

E. Added recommendations on maintenance, operating regime, process fluids, layup procedures, outage management, labeling, and ignition source control.

January 2008. This is the first publication of this document.

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