Property Risk Consulting Guidelines

A Publication of AXA XL Risk Consulting

PRC.17.12

ELECTRIC POWER GENERATION ABSTRACT

INTRODUCTION

This abstract describes the electric power generation process and introduces associated equipment, hazards and loss control techniques. The section titled “Elements of a Property Loss Control Program” lists many of the fire and boiler/machinery (B/M) loss prevention and protection methods prevalent at generating stations.

Electric power generation is generally associated with the electric utility industry, but this process exists on a smaller scale in other industries. Paper mills, steel mills, sugar mills, large oil refineries and chemical plants often generate all or a portion of their electricity.

NFPA 850 present basic property fire protection guidance for the electric utility industry. PRC.17.12.1 and the other PRC Guidelines referenced herein expand on that guidance to guide more comprehensive loss control programs.

A single incident can damage property worth millions of dollars and can halt power generation at a facility for years. Incidents can be formidable. As examples,

- A 40-ton (36-tonne) rotor of a modern generator spinning at 3600 rpm starts an excursion due to excessive vibration;
- A firebox explosion due to leaking or unburned fuel results in the boiler capsule to be severely damaged, including damage to the superheaters, reheaters, and other downstream attachments to the boiler;
- A forced draft fan drive motor fails allowing an induced draft fan to create a boiler vacuum, collapsing furnace walls;
- A steam stop valve binds causing an overspeed condition which results in destruction of the turbine;
- Vibration causes a lubricating oil line to rupture, and upon ignition of the oil, a severe fire occurs;
- A feedwater line fails leaving only 90 s for operators to reset and shut down the boiler before it overheats.

A wide range of hazards are encountered in the power industry. These involve many of the same types of processes and equipment found in other industries.

The high value and large size of the equipment used by the electric power industry should not cause undue concern. The same loss prevention and control principles used in other industries also apply to the electric power industry.

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By managing the hazards with a comprehensive management loss control program, like AXA XL Risk Consulting's *OVERVIEW*, the security of continued power output is heightened. A well-engineered facility and trained employees are important to this program. Also needed are adequate instrumentation, control systems, fixed protection, and a predictive and preventive maintenance program that not only covers the equipment needed to produce electricity, but also the equipment that controls and protects the production equipment.

This guideline only briefly touches the subject of loss control for the power industry. A good loss control program builds on the basics identified in this guide.

BACKGROUND

Steam drives the turbines which turn the generators to supply most of the electric power used around the world. Steam is usually produced by burning a fossil fuel, such as coal (sub-bituminous class or higher) oil or gas, in a power boiler. Less common fuels include lignite (the lowest grade coal), peat, biomass including wood waste and bagasse, refuse-derived fuel and solid waste.

Combined cycle plants produce steam using the waste heat from gas turbines or internal combustion engines. Industrial steam sources include the use of waste heat developed during manufacturing processes.

Solar heat collectors and nuclear fission are two other sources of heat for producing steam. Alternately, steam from geothermal reservoirs is used for electric power generation. Photovoltaic (solar panels) have become more efficient and reliable with largest sites generating up to 500 MW

Electric power is also produced by gas turbine-generators driven directly by hot combustion gases. Diesel oil and natural gas are common fuels. The fuel is mixed with air and burned in a combustor. The products of combustion drive the combustion turbine. Most combustion turbines are package units.

Generators are also spun by turbines driven by water and wind energy. Hydroelectric power generation is low cost where sufficient waterflow and head pressure exists. Wind turbines continue to be developed in areas with a sufficient wind resource. Individual wind turbines have only limited electric capacity, but a typical "wind farm" contains a large number of wind turbines (in excess of 50 units). Also, the size of wind turbines continues to increase, now to a maximum of 6 MW.

In some cases, electric power is a by-product of waste disposal. Examples include bark, off-gas and municipal solid waste (MSW) disposals. Pulping liquor recovery and steam pressure reduction are other processes whose byproducts include electric power. The term cogeneration applies when the electricity is an equal or subsidiary product.

A base load turbine-generator is one that is run fully loaded a majority of the time. For a utility, base load units will be the lowest cost per kW machines available. These are normally the newest and most efficient machines. Any nuclear, hydro, wind, geothermal or cogeneration facilities on a utility's grid will normally be included in the base load pool. Industrial and commercial cogeneration plants normally operate as base load units. Utility peaking units are brought on line as necessary to pick up the swing load which is the part of the load that exceeds the base load capacity. Peaking units have a higher cost per kW. These will normally include gas turbines and older, often smaller, steam power plants.

Generating units which are not actively supplying power to the grid, but are capable of doing so, are considered reserve units. Since steam power plants have a long startup period, they may be operated unloaded. In this case, they are sometimes referred to as a "spinning" reserve.

Internal combustion engine driven generators are often used to supply emergency electric power upon distribution or power system failures. Engine driven generators can be brought on line and fully loaded in seconds, compared to the hours that would be required for steam turbine units. Engine driven generators occasionally provide base load power, usually as part of a small utility or cogeneration scheme.

In the U.S., a steam turbine-generator generally produces 60 Hz electrical power by spinning at 1800 or 3600 rpm, with other speeds requiring the use of a gear set. Nuclear power plants utilize the 1800 rpm or 4 pole generator arrangements while almost all fossil fuel fired units utilize the 3600 rpm units. The generators used in a hydroelectric facility are larger in size, have a different winding arrangement, and usually turn at or below 360 rpm. Occasionally, electrical power is required at some unusual frequency such as 25 Hz. This may be produced by specially designed generators, typically found only in older, large industrial facilities or for city subway mass transit. Unusual requirements like these warrant a review of the availability of equipment for repairs and replacement.

Among the major methods of power generation, certain generalizations may be made. Hydroelectric generating plants contain fewer fire hazards than do steam electric generating plants due to few hot surfaces. Cables from the generators to the transformers often contain oil and can be extensive in length. These cables are often located in tunnels with limited access or on top of the dam itself and fire preplanning is an important part of loss prevention for hydroelectric facilities. The fire hazards associated with a turbine-generator at a fossil fueled steam electric generating facility are similar to those at a nuclear electric generating facility, but fossil fuel turbines operate with higher steam temperatures and pressures. Thus, most of the fire hazards of electric power generation are represented at fossil fuel steam turbine generating facilities.

Public utilities generally monitor and control the power generation process much more closely than a private industry producing its own power. The focus on power generation as the single goal of the enterprise simplifies employee training and management decisions. Utilities usually have comparatively stable load demands and are more likely to have redundant systems, computer-assisted controls, and more efficient equipment and process flows. For these reasons, utilities normally operate with higher levels of reliability and safety.

The likelihood of loss is minimized by monitoring and closely controlling flows, combustion, vibration, stress, temperature, pressure, thermal expansion and many other variables. But loss prevention practices cannot assure the avoidance of all losses. Fixed protection systems are used to minimize losses. The greater the consequences of loss, the greater the prevention and protection needs.

MAJOR PROCESS

The major processes involved in the generation of electric power are straightforward. The fuels, types of drives, and the general similarity of hazards were discussed earlier.

Fossil fuel steam turbine generating stations are common suppliers of electric power. They embody the major hazards of the power industry. The power generation process can be represented by an example of electric power generation using steam as shown in Figure 1. For simplification, oil systems, motors, hotwells and controls including the feedwater regulator are not represented in the diagram. Also, relays and other electrical equipment downstream of the generator are not shown.

Following the sequence of the numbers in the diagram, the process equipment at this power generating station can be described as follows:

1. **FORCED DRAFT FAN(S)** - This fan forces fresh air through the system. The air flow is balanced with the flow through the induced draft fan (Item 5) to bring about total combustion of the fuel and maintain the proper boiler pressure differential. If the induced draft fan is lost, the pressures created in a boiler by continued operation of this fan could damage boiler walls and could cause leakage of gases from the boiler.

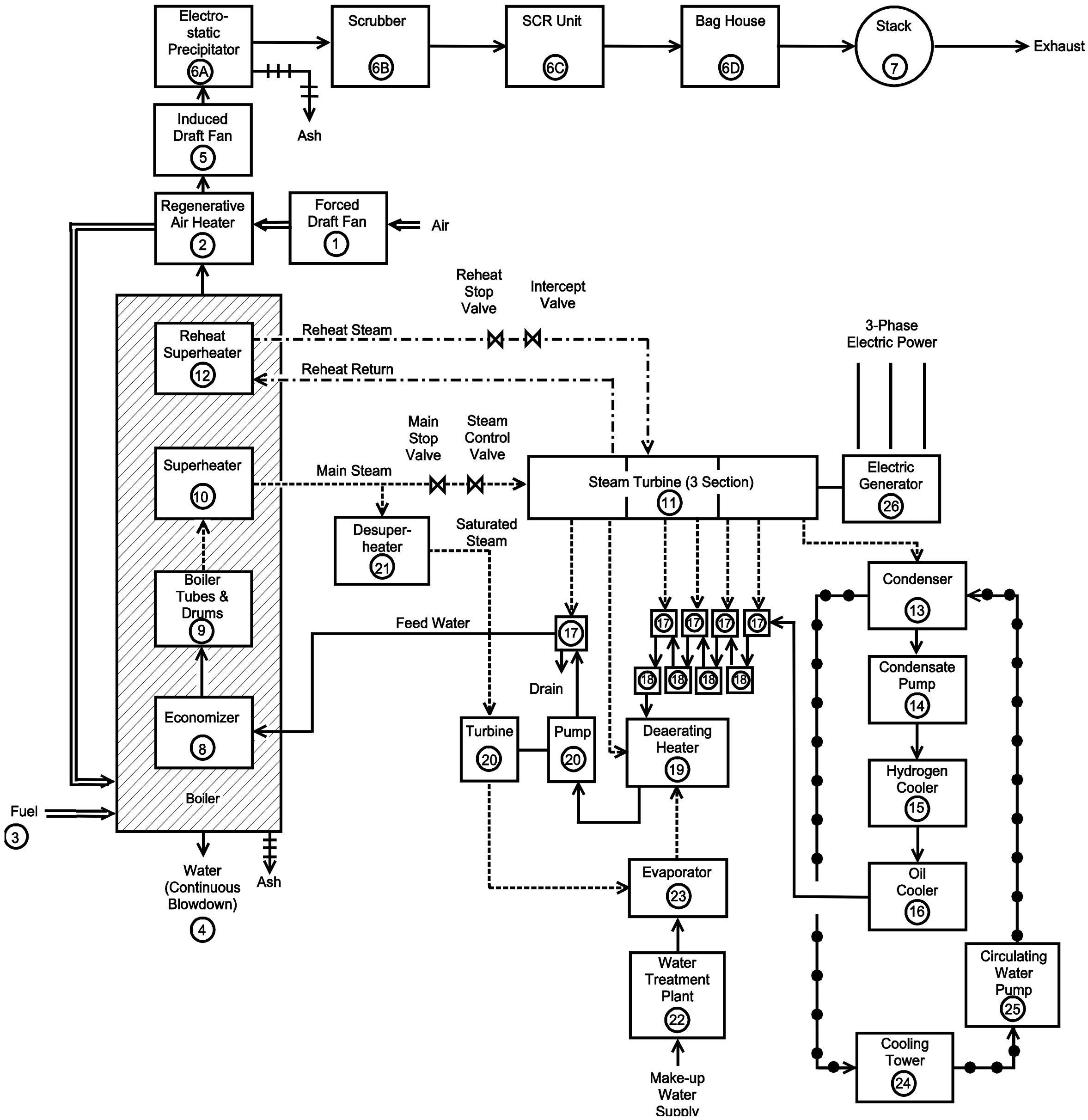

Figure 1. Example Of Large Power Plant.

2. **REGENERATIVE AIR HEATER** - Combustion air is preheated using flue gas which helps with plant efficiency and reduces the plant heat rate. The types of heaters are described under the main heading **AIR PRE-HEATERS**.

3. **FUEL** - This includes the receipt, storage, processing and delivery of fuel for use at a burner. Pulverized coal is the most common fuel used. About 1 lb (0.5 kg) coal and 11 lb (5 kg) air produce 1 kWh of electricity.

4. **BLOWDOWNS** - To remove impurities accumulated by boiler water, various blowdown connections are provided. There will normally be a blowoff (intermittent) from the lower drum or header, and a continuous blowdown from the steam drum and possibly other points in the boiler. Boiler operating procedures should document requirements.

5. **INDUCED DRAFT FAN(S)** - This unit is generally larger, more heavily built, more expensive, and more difficult to replace than the forced draft fan (Item 1). In addition to moving air supplied by the forced draft fan, it must move the gas equivalent of the fuel burned and must resist the erosive and corrosive effects of the combustion products. The higher temperature of the gas stream with its resultant lower density causes this fan to be less efficient than the forced draft fan, contributing to the need for increased size. If the forced draft fan is lost, the vacuum created in the boiler by the continued operation of the induced draft fan could implode the boiler walls.
6. **ELECTROSTATIC PRECIPITATOR(S), SCRUBBER(S), SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM(S), CYCLONE SEPARATOR(S), BAG-HOUSES, or FLUE GAS DESULFURIZATION (FGD) SYSTEM** (or some combination) - Treatment of the flue gas may be necessary to operate the boiler without causing pollution in the surrounding community.
7. **STACK -** A high stack assists the fans (described earlier) in driving hot gases through the boiler system and also disperses flue gases high above plant grade. A stack may require protection from lightning and corrosive flue gases.
8. **ECONOMIZER** - Physically located at the end of the flue gas path before the air pre-heater, this section of the boiler uses heat from the combustion gases to raise the feedwater temperature which helps with plant efficiency.
9. **PRIMARY BOILER COMPONENTS -** The main parts of the boiler or steam generator are the burner, steam drum, lower (mud) drum or header, waterwalls, and generating tubes; large units may also contain one or more superheaters or reheaters. Supercritical boilers (not shown) do not use drums as all water flows through the boiler in a path formed by tubes connecting the feedwater supply to the main steam line. In these “Once Through” boilers, water is converted to steam as it passes through the tubes; the water/steam interface changes with changes in the firing rate and with changes in the feedwater pumping rate.
10. **SUPERHEATER -** This section of the boiler raises the temperature and, therefore, the energy content of the saturated steam. Main steam is delivered to the boiler outlet at pressures up to 3800 psi (262 bar) and temperatures up to 1000°F (538°C).
11. **TURBINE** – Figure 1 shows a 3-casing, tandem compounded condensing turbine with reheat.
12. **REHEAT SUPERHEATER -** Also called a reheater, this section of the boiler reheats steam from the high pressure casing before it is passed to the intermediate pressure casing. It may take steam exiting the high pressure section at 400°F (204°C) and reheat it to almost the original main steam temperature but at lower pressure. This helps with plant efficiency.
13. **CONDENSER** - Exhaust steam is cooled and condenses to pure water that can be recycled. The condenser operates at a vacuum to improve thermal efficiency. The condensate accumulates in the lower portion of the condenser which is called a hotwell. The hotwell may be located in a pit below the turbine. The system for removing air and noncondensable gases from the condenser is not shown.
14. **CONDENSATE PUMP -** Water from the hotwell is pumped through the hydrogen and oil coolers to the feedwater heaters. Because the vacuum in a condenser may draw air into the system, air may have to be removed from the water. Combination condensate-air pumps may be used to accomplish this.
15. **HYDROGEN COOLER -** The hydrogen used to cool generator windings accumulates heat. This heat may be put back into the system by transferring it to the condensate.
16. **OIL COOLER** - Heat picked up by the oil at the bearings is transferred to the condensate.

17. **REGENERATIVE FEEDWATER HEATERS** - Several heaters are used to bring the heat up in steps before feedwater enters the boiler. The heaters use steam and condensate from the various turbine interstage drains. Open and closed heaters are used. An open heater is like a steel drum in which steam and water mix. In a closed feedwater heater, steam heats the tubes carrying the water; a condensate drain is needed. The final heater is closed. Each extraction line from the turbine contains a nonreturn (check) valve to prevent back-flow of steam upon shutdown and to prevent water/cool vapor induction at any time.
18. **INTERSTAGE FEEDWATER PUMPS** - Usually electric motor driven, these pumps provide a stepped increase in water pressure to keep the feedwater flowing against the turbine steam pressure which increases at each heating stage.
19. **DEAERATING HEATER** - The feedwater mixture is heated to near saturation temperature to remove oxygen and other gases.
20. **MAIN FEEDWATER PUMP** - A turbine-driven boiler-feed pump supplies the boiler feedwater regulator with water at a pressure above the main steam pressure in the steam drum. The use of multiple pumps in parallel allows pump maintenance to take place without interrupting the feedwater supply. Electric drive pumps are also common.
21. **DESUPERHEATER** - Also known as an attemperator, this is where steam pressure is reduced and the steam is cooled to saturation temperature so it can be used in typical small turbines or for other auxiliary needs.
22. **WATER TREATMENT PLANT** - Chemical treatment of water reduces scale-forming materials and oxygen.
23. **EVAPORATOR** - Contaminants are removed from water using this alternative to chemical demineralization.
24. **COOLING TOWER** - The main circulating water, which is heated in the condenser, is cooled in this tower and recirculated. Some installations use single-pass, treated river (bay) water.
25. **CIRCULATING WATER PUMP** - This pump may be very large - e.g., 270,000 gpm (1,020,600 L/min).
26. **ELECTRIC GENERATOR** - This is the heart of the system. While a generated voltage may be high, e.g., 26 kV, it is often necessary to step up the voltage with transformers, to 69 kV – 765 kV for connection to a high voltage transmission network, usually called the “power grid.” Generator operation is described in the next section of this guide, **THE TURBINE-GENERATOR**.

Generally, fuel handling, steam generation, and pollution control account for 60% of the property value of a facility. The electric generator and associated cables, transformers, and switchgear account for around 16% of the value. The remaining 24% applies to the steam turbine and associated equipment. However, portions of both the generator and the turbine can be damaged from the same loss.

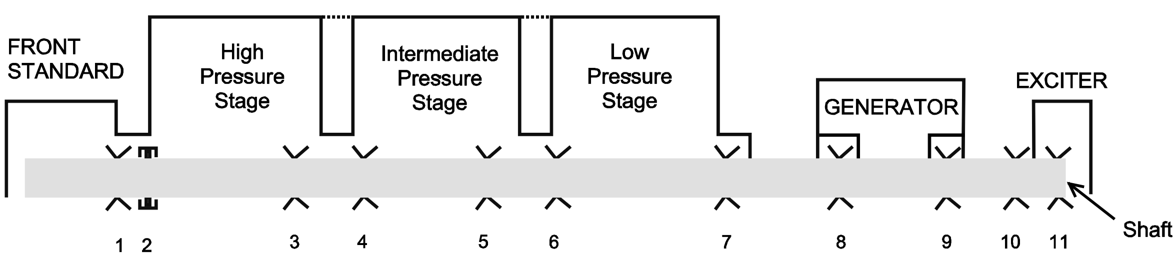

Figure 2. Turbine-Generator Arrangement.

THE TURBINE-GENERATOR

Many different steam turbine-generator arrangements exist. One common arrangement is shown in Figure 2. When viewed from the operating floor, the turbine-generator may appear to be several aligned enclosures on what appears to be one continuous shaft.

Normally, the turbine shaft is formed by the coupling of several shaft segments. Bearings are needed at both ends of each segment. In Figure 2, bearings 1 and 3 support the first segment of the shaft, 4 and 5 the next, and so on. Additionally, a thrust bearing (bearing 2) is required to counteract the lateral thrust created by the steam flow, thus maintaining the correct axial alignment of the rotor. Damage to operating bearings can result in loss of clearance resulting in possible rubs between the rotating parts and either the stationary vanes or the shell itself creating vibration or excessive heat.

The front standard supports one end of the shaft, at bearing 1 which is at the high steam temperature and pressure end of the turbine. The front standard, bearing 1, and nearby control and protective equipment, including steam stop valves, hydraulic piping, the speed control governor, low oil pressure switches, the mechanical overspeed trip, and lubrication piping, may be located in a single enclosure at one end of the shaft.

The steam turbine casing(s) is next. Figure 2 shows high, intermediate and low pressure casings connected in a line driving a single generator to form one unit.

The ultimate hazards to a turbine are centrifugal destruction of the rotor and pressurized rupture of the casing. Even lesser events such as rubbing, cracking and bearing failure may involve substantial loss. The cost of opening and closing a large turbine can easily exceed $1,000,000.

Turbines are subject to severe damage if any water or low-temperature steam is allowed to enter a hot or operating unit. Therefore, a formal program for water/cool vapor induction protection in accordance with current ASME standards or the equivalent is needed to control this hazard.

As sophisticated as the on-line performance monitoring and testing may be, the only way to examine many parts of the turbine is by dismantle and overhaul. Peaking turbines will require more frequent overhaul due to the additional stress imposed by frequent startup and shutdown as well as load changes. Records of all disassemblies, rundown and runup vibration signatures, photographs and various other supporting information can be used to assist in tracking conditions between overhauls.

Utility turbines do have generic difficulties and may be subject to manufacturer's post-operational recommendations. Manufacturers finding such problems will issue notices (Turbine Information Letters, etc.) so that users may take appropriate action. Plant engineering personnel should be aware of any outstanding bulletins and should deal with the problems outlined.

For units rated over 10 MW, a turning gear is usually provided to slowly rotate the shaft during warm-up, cool-down and standby to prevent shaft sag and thermal distortion, also known as rotor bowing. Backup power supplies are usually provided. The turning gear is likely to be found between the turbine and the generator, but it is sometimes found at the front standard.

The next enclosure along the shaft is the generator shown in Figure 2. To function, the generator uses the mechanical energy of a turning shaft and a dc power source, such as an exciter. Field coils, wound on the rotor of the generator, turn with the shaft. When a dc excitation current is supplied to these rotating field coils, a rotating magnetic field is produced within the generator. The rotating magnetic field induces an alternating voltage across the stator windings (stationary coils). When a load is connected to these stator windings, an ac current flows. Most generators are rated between 100 kW and 1300 MW.

For electrical generators rated below 15 MW, air cooling of the windings is common. For generators rated 15 MW and above, pressurized hydrogen is often used for cooling. Hydrogen is a more efficient heat transfer medium than air and produces less resistance to the turning of the rotor (windage).

Where hydrogen is used, nitrogen cylinders or low pressure carbon dioxide storage tanks are commonly connected to the system. The inert gas is piped into the generator to force the air out before the hydrogen atmosphere is introduced. The gas is then displaced by hydrogen, and the generator can be energized. Upon shutdown, the gas is again used to purge the equipment.

Direct cooling of conductors is usually found in generators rated over 90 MW. With direct cooling, hydrogen at a pressure of 15 psi – 75 psi (1.0 bar – 5.2 bar), oil or de-ionized water flow within hollow stator conductor bars to supplement the indirect cooling. With direct cooling, electrical insulation is not in the main heat transfer path; the insulation stays cooler and has a much longer life.

The exciter is the final enclosure at the end of the shaft in Figure 2. An exciter is an electrical system that includes an ac generator and rectifier, a dc generator, or a solid state rectifier which can be located far from the unit. It provides the dc excitation current described earlier. An exciter may be a rotating type, whereby a rotating shaft is used to create electrical energy, or a static type, whereby electrical devices rectify a separate ac power supply to dc. A rotating exciter may be directly connected, meaning the turbine-generator shaft extends to and is part of the exciter. A rotating exciter may have field windings, thus requiring a dc power supply (smaller than the supply needed for the generator) to produce a magnetic field or it may use permanent magnets.

Where an exciter is not located near the generator, it may be in a separate fire area, remote from the unit. Most exciters supply dc current to the generator field windings by means of graphite brushes that ride on collector rings on the shaft at the generator.

In contrast with turbines, generators and electrical equipment tend to have fewer and less severe problems, due in part to construction, relays and controls. The major exceptions involving generators have been failures of shaft mounted fans, hydrogen blower spacers and end-turn insulation. However, because of the length of time needed to replace major rotating equipment, spare components may be useful to loss control programs.

Additional references to steam turbine arrangement, process and protection are in PRC.6.1.0.1 and PRC.6.1.1.0.2. References to combustion turbine design, process and protection include PRC.6.1.2.2 and PRC.6.1.2.3.

Various utility industry organizations compile records of performance and issue reports identifying components, operating experiences and outages. This statistical data is helpful in identifying to the industry problem areas for study and possible improvements.

ROOMS CONTAINING MAJOR ELECTRICAL EQUIPMENT

The entire production process at the generating station is controlled from a control room complex which is critical to the operation of the generating plant. A major control room complex includes the following:

- Central control room where control and instrument panels and personnel are located;
- Computer room housing a process computer to control production;
- Cable spreading room where perhaps thousands of signal cables from the central control room pass and are routed in trays to other power station locations;
- Relay room where control relays are located in rows of equipment racks;
- Switchgear rooms (480v and 4160v);
- Battery room.

Special attention is given to protecting the central control room from exposure fire and smoke since emergency actions by operators within the room are necessary for loss control. Good room design provides protection for operators against smoke and heat from external fires and allows emergency procedures to be followed during an exposure fire. Smoking is normally prohibited to minimize sources of ignition and contamination to instrumentation. Arrange the fresh air for the central control room to come from an outside source not subject to drawing in contaminants (smoke). At no time should it come from the turbine building.

The cable spreading room, or wiring gallery, is the “spinal cord” of the plant’s communication and operating control systems. This area is not constantly attended and represents a unique loss potential. A fire would produce heavy smoke. Because of the maze of cables, access would be difficult for manual firefighting. The concentration of combustible cable insulation is much more extensive here than in any other area of the plant.

Batteries provide power to drive dc motors, supply inverters with the input needed for emergency ac supplies in Uninterruptible Power Supply (UPS) systems, and control power for switchgear. Battery rooms are built to isolate, protect and improve the reliability of this dc power. The greatest threat to a battery room is the hydrogen which is generated by batteries during discharging and recharging. Ventilation is designed to keep the concentration of hydrogen well below the lower flammable limit of 4% by volume. Adequate constant ventilation, construction features to prevent hydrogen accumulating in pockets, and electrical equipment prohibited from the ventilation path, eliminate the need to designate the room as a hazardous (classified) area.

Electrical room fire and smoke hazards are described in PRC.5.0.3. Battery reliability and related loss control issues are discussed in PRC.5.6.1 and PRC.5.7.4.

LUBRICATING OIL SYSTEM

The major turbine-generator fire potential is produced by combustible oil used for lubrication and seals along the shaft. The main reservoir for turbine lube oil may contain more than 12,000 gal (45,360 L) of oil which can be classed as a Class III-B combustible liquid by NFPA 30. The oil pressure is usually maintained at about 25 psi (1.7 bar) at the bearings; this may require 40 psi – 100 psi (2.8 bar – 6.9 bar) pressure at the pump. Much research continues on applying lubricating oils that are less flammable throughout. This type of material must be reviewed by the turbine-generator manufacturer for application for older units. Some newer units can use this less flammable oil and may not need special fire protection and should be reviewed on a case by case basis.

To prevent overheating of the turbine bearings, the lube oil system is provided with two main oil coolers (one reserve) to lower the oil temperature to about 120°F (49°C) before returning it to the bearings. The oil also passes through a series of filters. These filters are usually located near the main lube oil reservoir on the Ground or Mezzanine Level of the Turbine Building. However, smaller, more localized filter units may be located at or very near specific bearing assemblies on the Operating Level of the Turbine Building depending on the oil quality the facility is trying to achieve.

Oil samples and oil filters are regularly tested to assure that proper lubricating characteristics are maintained and that no traces of metals are found in the oil. Contaminants might suggest excessive bearing wear.

To prevent machinery damage from loss of lubricating oil, high reliability is built into the system. Usually, during normal turbine-generator operation, a shaft-driven main oil pump supplies lube oil. For start-ups and shutdowns and emergency situations, two motor-driven pumps with separate power supplies are used. One of these emergency pumps is ac and the other dc. High pressure nitrogen cylinders are sometimes used to drive lubrication systems.

This same oil may be pumped to a second reservoir supplying a separate pumping system to provide hydrogen seals. The hydrogen seal oil system is described later.

The turbine lube oil system, including the distribution piping, associated reservoirs, pumps and filters, presents a potential for escaping combustible oil. Oil may escape from damaged bearings or broken oil lines and cascade over other equipment as it flows to the lowest level. Since the auto-ignition temperature of the oil is about 700°F (371°C), it can be ignited by contact with the hot turbine casing, steam piping or valves, mechanical sparks, electrical lighting fixtures or one of any number of sources. Once ignited, an intense and rapidly spreading fire ensues. Where a steel grating allows the oil to drip, a three-dimensional fire results in a very difficult fire-control situation. Fires involving oil sprayed from broken piping will resemble the flames from a blowtorch.

To minimize the likelihood of turbine vibration rupturing an oil line, welded piping is used. Also, long continuous runs of oil line piping are protected with guard pipe construction. The pressurized oil line is located inside a concentric pipe to confine escaping oil and convey it to a point of safe discharge. Guard piping may return the oil to a tank or discharge it at some remote location at atmospheric pressure. Commonly, the guard piping system also serves as a return oil piping system. Flange guards, used for both oil and hydraulic system flanged oil connections are also used to deflect escaping oil.

Placing storage reservoirs and filters far from the turbine-generator and in a separate fire area will lower the fire loss potential and will assist firefighting efforts. However, it will still be necessary to pump oil for seals and lubrication to the turbine-generator until hydrogen has been dumped and the unit coasts down to turning gear speed. This required pumping will result in a continuing supply of oil to a fire even though the oil storage is remote.

HYDROGEN SYSTEM AND HYDROGEN SEAL OIL SYSTEM

The hydrogen used for cooling the generator is typically supplied from bulk storage cylinders containing as much as 50,000 ft^3 (1416 m^3).

The flammable range of hydrogen is 4% – 75% by volume in air. In a confined space, it will explode. Hydrogen cylinders are very dangerous if located in a confined space or near equipment which might expose the storage to a fire. Because hydrogen is lighter than air, the leakage of gas in an enclosure may form pockets of gas concentrations at high elevations.

To prevent the escape of hydrogen at the generator shaft, an oil seal is provided. The same oil supply used to lubricate the bearings may provide this seal. Oil from the main lube system reservoir may be pumped into the seal oil system. In this system, the oil is vacuum treated to minimize air content. The oil is then pumped to its own reservoir, filtered and finally pumped to and discharged against the shaft at both ends of the generator to form seals which confine the hydrogen to the generator. The oil pressure needed to maintain the seal is normally at least 10 psi (0.7 bar) above the hydrogen pressure. The interfacing of hydrogen and oil on the inside of each seal, and the interfacing of air and oil on the outside of each seal, allow these gases to be entrained into the oil. Detraining equipment removes the gases so the oil can be recirculated. For high reliability and redundancy, both ac and dc motor driven emergency pumps with separate power supplies are usually installed.

The hydrogen seals present a unique and significant fire potential. Failure of the seals can result in the release of hydrogen and oil. The hydrogen will easily ignite, and the oil will produce a very severe fire.

A vital part of a hydrogen seal oil system is a filtering arrangement provided to clean the recirculating oil. These filters require periodic cleaning. Maintenance procedures must be clearly written. The story of a past large loss will clarify this concern.

> *Instrumentation in a turbine-generator dual-filter oil seal system detected a pressure differential across the north on-line filter, indicating the need for cleaning. An operator was assigned to tag the valves, operate the 3-way selector valve to switch the filter off-line and bring the standby filter on-line, and service the "dirty" unit. This service involves venting trapped pressure, draining trapped oil, and then opening and cleaning the unit. When the job is completed, the on-line unit is left in service and the newly cleaned unit remains on standby. Normal procedures were followed; however, before the cleaning could be completed, the operator was called away on another job and was relieved by a less experienced employee. Upon finishing the job on the north filter, this employee, without authorization, began to open the south unit without changing the selector valve or opening the vent. The resulting escape of oil ignited upon contact with a hot surface. The oil had a flash point of 338°F (170°C), a pressure of 90 psi (6.2 bar), and the oil system capacity was over 10,000 gal (37,800 L). Operator error and inadequate employee training with reference to maintenance procedures appear to be the cause of this loss.*

HYDRAULIC CONTROL OIL

Hydraulic control systems operate the main steam stop and control valves, reheat and intercept valves, the governor and other devices. Hydraulic oil pressures may be as high as 3000 psi (207 bar). The system must provide high reliability to shut off the steam supply whenever an emergency turbine shutdown (trip) is required. Frequent exercising of the valves and control systems is a common method of verifying system readiness. See PRC.9.2.4 for a discussion of hydraulic fluids and their fire hazards. Electro Hydraulic Control (EHC) is often used to direct/control the hydraulic fluid ported to an actuator. This can be adjusted to shutdown fluids in their entirety or operate at reduced pressures. Changing the type of hydraulic oil is being considered all over the world to use Less Flammable Liquid (LFL) with one such type is Firequel. Some older power plants have a combination hydraulic and lubricating oil system that presents problems for a holistic replacement of the oil.

BOILERS AND STEAM

A utility boiler generates steam by combusting a fuel and using the resulting heat to convert water to steam. If combustion is incomplete due to improper fuel temperature or pressure, combustion air temperature or flow, mechanical rotation or atomization, fuel particle size or flow rate, burner design or impurities in the fuel, problems can occur. Unburned fuel passing through the boiler can become deposited on interior surfaces of the boiler and exhaust equipment. Inefficient heat transfer, fire and pollution can result. Rapid and delayed ignition of unburned fuel outside of the normal combustion zone in the boiler can result in both explosion and fire damage. Boiler controls that govern the effectiveness and stability of combustion are generically called combustion controls.

Excessive steam pressures result in equipment rupture. Safety relief valves are the primary form of overpressure control. Usually, they are sized and provided in sufficient numbers to reliably relieve all the steam which the boiler can produce. Maintenance programs include testing these valves to assure that they function properly.

Even normal steam pressures can cause containment rupture. Equipment in use deteriorates continually. The rate of deterioration determines its service life. Some actions can slow the rate of deterioration, or conversely, lack of actions can speed deterioration.

The service life of boiler tubes, turbine blading and other plant components depends on the maintenance of high-purity boiler feedwater. The traditional chemical treatment and deaerating techniques may be supplemented by current technology involving steam-purity monitoring and control, and treatment of condensate.

Overheating due to low water is a frequent cause of boiler loss. Equipment for observing and maintaining the water level (or flow for a “once-through” boiler, or circulation for a forced-circulation boiler or both) must be highly reliable. Normally, two independent means of pumping the boiler water are provided. A single failure should not affect both pumps when one is steam-turbine driven and the other is electric driven and supplied by a dedicated emergency generator. Normally two independent systems of remote water level indication are employed, and one is direct. Examples of direct means include conveying the gauge image by mirrors, television, fiber-optics or density differential detectors.

Procedures for inspection and weld repair of boiler and vessel components and piping should be fully documented. Most states require compliance with the National Board of Inspection Code (NBIC) for weld repairs and alterations.

Most aspects of boiler and pressure vessel operation will involve the laws of the jurisdiction in which the equipment is located. Where these laws are more restrictive than AXA XL Risk Consulting standards, the laws will be substituted.

For further discussions of utility boiler features, operations, loss control concerns and protection, see PRC.7.1.0.6, and PRC.7.1.1.0.

AIR PRE-HEATERS

Plant designers and operators strive to increase the efficiency of the power generation process. Combustion air may be preheated by passing it through a regenerative or a recuperative air heater. These air pre-heaters reclaim some of the heat that would be wasted in the flue gas and transfer heat to the combustion air before the air is introduced into a boiler. This process has the added benefit of cooling the exhaust gases to manageable temperatures.

There are two basic designs for the regenerative air heater. Both use a heavy steel plate-shaped structure as a heat sink. In one, the plate (rotor) rotates in a stationary enclosure, and, in the other, the plate (stator) is stationary and hoods and ducts rotate around it. Combustion air temperature is increased as air flows by the heated portion of the steel plate, cooling that segment of the plate. The plate segment is reheated when rotation places it back in the flue gas stream. The process is continuous as the plate or hoods and ducts rotate past 360° to complete one heating cycle and begin another. The rotation system and bearings are critical; if rotation stops, plates can be damaged.

Regenerative air heater fires normally occur at start-up, when changing loads, during upset conditions with less than ideal combustion control settings, or when a pre-heater bearing lubrication system fails. This phenomena is more characteristic of oil fired plants than other fossil fuel fired plants The carryover of unburned fuel condenses on the heat transfer plates. High pressure water wash systems keep the plates clean, but these are manually actuated and do not prevent unburned fuel from accumulating. Air heater fires can be severe. Typical fire detection devices may be slow to operate.

Another method uses a recuperative air heater. This is a heat exchanger where heated combustion gases pass directly through plates or tubes, while the separate incoming combustion air passes around these heaters. These are not as prone to fire losses as are regenerative air heaters.

Air pre-heaters are rarely involved in fires where there are good combustion control systems, good maintenance and housekeeping programs, and generally stable operating conditions. When fires do occur, they can be extremely severe and difficult to extinguish often due to the units being high up at the site along with the difficulty of getting water With either type of heater, a fuel-rich condition may cause unburned oil or coal to collect not only in the air heater but also downstream in the ductwork, precipitator, bag-type dust collectors, hoppers, scrubber, fans and stacks.

POLLUTION CONTROL

Regulations to protect the environment and environmental and liability concerns have had major impacts on the power generation industry. Pollution control includes both fuel preparation and flue gas handling.

To meet air quality standards and to remain “a good neighbor,” coal-fired power plants use electrostatic precipitators, bag-houses with fabric filters, and cyclones to remove particulates from the flue gas stream. To meet ever more stringent pollution control laws, power plants now use wet and dry scrubbers along with chemical treatments including Selective Catalytic Reduction (SCR) to remove sulfur dioxide and nitrous oxides from exhaust gases. Bag-houses have another pollution control use; they can be used to control coal dust during fuel handling prior to burning. Another pollution control issue involves the control of elemental mercury in the flue gas. This is currently being accomplished through the introduction of activated carbon in the flue gas. The mercury particles attach to the carbon particles and are captured in a baghouse installed downstream of the other pollution equipment.

Fires in pollution control equipment may be very difficult to detect in the early stages and extremely hard to control unless fire protection features are incorporated into the original design of the equipment. Equipment design that does not allow for a fixed fire protection installation is likely to sustain a greater loss. A fire in pollution control equipment will burn not only dust and unburned products of boiler combustion but also combustible bag filters, combustible liners in scrubbers, and sometimes even structural components of the equipment. Thus, extraneous combustibles must be avoided.

Problems that can occur include:

- Fabric filters can be ignited if gas temperatures rise too high.
- Combustible bags can be ignited by burning particulates carried over from the steam generator.
- Unburned fuel from over-rich firing of a boiler can be ignited by arcing inside a precipitator. Fires in electrostatic precipitators can warp collecting plates and framing.
- Cutting and welding during construction and maintenance shutdowns can cause fires in bag-type dust collectors, scrubbers and associated ductwork. The use of combustibles in the fabrication of equipment is often necessary due to the challenging environment inside the equipment, and exposes the entire unit to a serious loss even where the structural framework is noncombustible.

COAL HANDLING

Coal is mostly carbon combined with small amounts of moisture, hydrogen, sulfur, nitrogen, oxygen and mineral ash. As coal is formed, its usual development stages are lignite to sub-bituminous to bituminous to anthracite. Its heating value and rank (rating) generally increase during the process. Lignite is a soft, brownish coal still evidencing the original wood structure. The highest grade of coal is anthracite, a clean, hard, shiny coal with low volatile and low oxygen content.

Coal is received in a variety of ways including rail car, ship, barge and overland conveyor. It is unloaded by dumping or by automated scavenger conveyors and stored in piles. A 90-day supply, or 1,000,000 short tons (907 k tonnes), may be in storage. After removal from storage, coal is generally crushed into pebble-sized pieces and transferred to a bunker or bins inside the plant. When needed for burner firing, it is passed from the bunker to a pulverizer where it is ground to a powder consistency and then fed with a high velocity air stream at up to 5000 ft/min (1525 m/min) to a burner. The pulverized coal burned in power plants is usually sub-bituminous. Anthracite is rarely pulverized; it is usually fired in stoker-fed boilers, which are rare at electric utility power plants.

With all but high grade anthracite, spontaneous combustion in coal pile storage is most likely where any of the following exist:

- The coal has been mined within the past 4 months.
- The coal is in small particles or is easily breakable.
- There are impurities in the coal including moisture, sulfur compounds or low grade coal.
- There are impurities in the coal pile such as trapped air or gases, wood chips, leaves or trash.
- The pile is exposed to heat from transformers, buried steam lines, or the like.
- The pile has not been tightly packed.
- The coal has been exposed to excessive handling.
- Rainwater runoff is poor.

Heating equipment, motors and switchgear are all possible sources of ignition to coal dust. If storage is left idle, spontaneous combustion can result. Spontaneous combustion of coal and coal dust may result in major fires or explosions in bag-type dust collectors, hoppers, conveyor galleries, and other storage or accumulation points. If a collector is left idle with accumulated dust not removed, a smoldering fire may occur from spontaneous heating of the dust; when the system is restarted in the presence of a smoldering fire, an incoming dust cloud may be ignited explosively.

Dust accumulations around the conveyors installed above the coal silos could lead to an explosion or rapidly spreading fire. Generally, fires in coal bunkers and silos located within the plant are almost impossible to detect except by smell or by observing hot, glowing sections of the hopper. Carbon Monoxide (CO) monitoring is one approach to early detection of a fire in a silo.

Fires in coal feeders are infrequent, but they do occur. A feeder fire usually occurs when the feeder is not empty and the pulverizer is shut down. The coal remaining on the belt or in the pulverizer spontaneously heats and ultimately ignites.

Pulverizer fires and explosions may be caused by spontaneous heating of coal left in the pulverizer when an emergency trip occurs, or when it overheats from excessive friction. Fire from the boiler's pressurized furnace can also back down the coal pipes to the pulverizer. Although rare, unused blasting caps have been known to reach the pulverizer and cause an explosion.

Failure of any of the piping carrying suspended coal dust between the pulverizer and burner can release an explosive cloud of coal dust which creates a blowtorch effect if it is ignited. Piping failures usually occur at bends where coal erodes the piping.

Coal conveyor fires are generally started by friction between the belt and rollers or pulleys that have seized or which are improperly aligned. Also, coal conveyors are particularly subject to exposure fires from occupancies at each termination, surrounding structures, and from the coal pile. Grass, weeds, feeder conveyors, bins and accumulations of coal from hang-ups or leaks in the system also can expose a conveyor to fire.

When a coal conveyor catches fire, the conveyor itself, as well as upstream and downstream conveyors and other associated equipment (e.g., a dust collection system serving the conveyor), can allow burning material to spread. When conveyors are enclosed, the enclosure will contain the heat and create a chimney effect. Fire may pass through to surge bins or drop chutes. Burning embers may be drawn into the dust collectors. There is risk of fire and explosion spreading to other equipment. This may accelerate the horizontal spread of fire causing the involvement of other structures and buildings. When conveyors are located high above ground, alternate means of coal transfer may be impossible, so a major conveyor fire may result in a complete shutdown until reconstruction is complete.

US coal fired power plants built in the 1950's through the 1970's typically used the high sulfur coal found in Illinois, West Virginia, Pennsylvania and Virginia. Several facilities were constructed, during this time frame, in the western US, utilizing the low sulfur sub-bituminous coals that are found in the Powder River Basin area of Montana, Wyoming and Colorado. With the advent of the Clean Air Act, it was found that it was easier to switch coal use to coals from the Powder River Basin (PRB coals), than it was to install very expensive scrubber systems for an existing plant. The problem with this, though, is that the volatile nature of PRB coals introduced coal-handling hazards into plants that never had any problems at all with coal handling. This resulted in numerous fires involving conveyor systems, dust explosions, coal storage fires, including silo fires, and pulverizer problems. The unique hazards to using PRB coal are now well known and significant protection/operational improvements must be made before a plant can "switch" coal use to PRB coal A sprinkler system designed to protect the structure and stop fire spread, along with conveyor interlocks and manual hose streams, will minimize belt damage. An adequate supply of spare belting will allow quick repairs.

PRC.9.3.1 provides additional information concerning construction and protection of belt conveyors.

Changing types of coal is not simple and a major review of all site operations needs to be completed as often major physical modifications will need to be made. This can include adding surfactant applications (to keep dust limited), dust covers on belts especially at transfer points, surface areas changed to not allow dust buildup (angled to let dust fall off), added dust collection, etc. Housekeeping is one of the major focuses including washdowns and physical changes to drain the water.

FUEL OIL HANDLING

Fuel oil is a hydrocarbon compound. It is classified into grades, depending on the refining process and oil characteristics. Unrefined crude oil, for example, contains a mix of light, volatile and heavy, or tar compounds. The mixture varies from source to source. Crude oil presents an explosion potential because of its many volatile light fractions which have flash points well below ambient temperature. Crude oil is a Class I flammable liquid and a potential boil-over liquid.

Number 6 (Bunker C) fuel oil is a refined, heavy residual which has a flash point at or above 140°F (60°C). It is treated as a Class III combustible liquid. Number 5 fuel oil is a light residual having a flash point of 130°F (55°C) or above. Number 4 fuel oil may be a heavy distillate having a flash point above 130°F (55°C), or a light residual having a flash point above 100°F (38°C). Numbers 1 and 2 fuel oils are considered light and middle distillates, respectively, and have a flash point of 100°F (38°C) or above, and are generally Class II combustible liquids.

Numbers 1, 2 and 4 fuel oils can generally be stored, pumped and atomized at the ambient temperature. They are not generally used for the main fuel supply in a power plant but rather for small heating furnaces and boilers. The higher numbered fuel oils must generally be heated and agitated to keep them fluid for effective pumping and boiler combustion.

Sizable aboveground storage tanks are necessary. Site topography is important to evaluate exposures including whether the escape of fuel can flow to waterways, important buildings or structures, and whether heavy hydrocarbon vapors will flow or be blown to a source of ignition. The value of a single tank and its contents can easily exceed $1,000,000.

The types of nonpressurized or atmospheric tanks commonly used for storage include cone-roof tanks, floating-roof tanks and internal floating-roof tanks. To prevent positive or negative overpressurization during oil filling and discharge, cone-roof tanks must be vented.

Where crude oil is stored in a cone-roof tank, the vapor space between the liquid surface and the roof of the tank is likely to contain a flammable or explosive mixture. This condition has lead to major losses.

A floating-roof tank has a roof that floats on the oil, eliminating the vapor space. The seal area between the walls and roofs of such tanks has been a problem area for tank fires. Leaking seals and poor electrical bonding between the roof and tank walls can result in fire upon a lightning strike.

Pan, single-deck pontoon and double-deck pontoon are three types of floating-roof tanks. The pan type costs the least but is susceptible to becoming submerged by wind, rain and snow loads. The single-deck pontoon contains built-in compartments to make the roof more buoyant. The double-deck pontoon roof has even more buoyancy.

For environmental reasons, many cone-roof tanks have been converted to internal floating-roof tanks, sometimes called “hard hat floaters.” A cone roof protects the internal roof, requiring less maintenance. These tanks limit fuel evaporation and pollution of the environment.

Strainers are usually upstream and filters downstream of oil pumps. Fixed piping carries oil under pressure from storage to the boiler. Where there is a long piping run between valves, a relief valve discharging to a tank return line prevents overpressurization of the pipe when the valves are shut and ambient temperatures rise.

The heavier oil distillates may be heated to 130°F (55°C) and pumped at about 100 psi (6.9 bar) pressure into the plant. Depending upon the atomizing method to be used, the pressure of the incoming fuel oil will be raised to between 150 psi (10.4 bar) and 300 psi (20.7 bar) for air or steam atomizing, or to 1000 psi (69 bar) for mechanical atomizing. Even a small crack in an oil line at these high pressures can cause an extensive spill or an easily ignited atomized spray.

GAS FUELS

Gas is normally piped to the premises. The use of a gas fuel warrants an analysis of explosion prevention and protection. Combustible gas monitors and explosion venting are common loss control measures for building areas subject to gas accumulations.

ELEMENTS OF A PROPERTY LOSS CONTROL PROGRAM

Losses are often a chain of events starting with one that is not easily detected. The chain can grow to a catastrophe. Turbine stresses can lead to metal fracture, rotor imbalance, vibration, bearing failure, the escape of oil and fire. Even major shaft excursion is possible. Loss control starts with detecting the fracture and making repairs, but backup controls including vibration monitors and temperature and fire detection all support more active protection programs and systems.

Many PRC Guidelines were referenced earlier. Others useful to the power industry include PRC.5.4.5, PRC.5.9.1 and PRC.5.9.2. The following is a synopsis of loss control actions that control the fire and B/M perils common to electric power generation. Neither this synopsis nor the referenced guidelines identify all of the loss control resources available.

- TURBINE-GENERATOR LUBE OIL, HYDRAULIC OIL, AND SEAL OIL SYSTEMS — high reliability with redundancy built into the systems; scheduled inspections and shutdown examinations; use of a less flammable hydraulic fluid; solid deck under oil piping; automatic sprinklers, deluge water spray, foam-water sprinklers, and AFFF protection for buildings and occupancies; shields to protect steam control valves, generator, and exciter from direct water spray; smoke and heat venting; also:
    - Reservoirs, pumps, tanks and filters — controlled exposures to other equipment using fire-rated cut-off, fire barrier or wide separation; alarms monitoring oil temperature, pressure, tank oil level; secure connections free of oil leakage; dikes and drains to collect any oil flow and pressurized oil spray.
    - Oil pumps — safe and reliable power supply; backup pumps with an independent power supply; pumps in safe operating condition.
    - Oil quality — lab examination of oil filter debris; monthly lab testing of oil properties including examination for trace metals; examination of water content following sprinkler operation.
    - Oil piping — welded piping; guard piping sized to safely carry all oil flow from a piping rupture to a safe location.
- TURBINE-GENERATOR SHAFT — instrumentation including overspeed trip and axial rotor position alarm and trip; alarms provided for eccentricity, differential expansion, vibration, speed, and rotor position; inspection of turning gear system and its power supplies.
- TURBINE-GENERATOR BEARINGS — vibration and temperature alarms; acoustic bearing wear monitoring; also:
    - Bearings on the turbine end — water spray protection.
    - Bearings on the exciter end — water spray or automatic carbon dioxide total-flooding protection.
- STEAM TURBINE — shut down authority; dismantled inspection frequency; history of machine and repairs; trip valve exercise and overspeed trip testing frequency; water/cool vapor induction protection; on-line, acoustic, blade monitoring; life extension analysis on units over 22 yrs old; control over property value allowed in an open area.
- STEAM PIPING — safety valve testing; suspension systems monitored; life extension analysis on reheat piping over 10 yrs old; life extension analysis on other piping over 900°F (482°C) and over 22 yrs old.
- EXCITER — insulation resistance tests; instrumentation and controls; vibration monitoring; automatic carbon dioxide flooding; high reliability of power supply.
- GENERATOR — instrumentation and controls including relays; direct cooling; maintaining of hydrogen concentration (also see “hydrogen cooling system”); vibration monitoring; dry inert purging atmosphere for shutdown and start-up; also:
    - Connections — scheduled examination of brush wear, tension and rigging.
    - Rotor and stator windings — insulation resistance tests.
- HYDROGEN COOLING SYSTEM — controlled exposures; concentration, pressure, and temperature alarms; purging system; also:
    - Bulk storage — outdoors; detached; cylinders secured and protected from mechanical damage; water spray for exposures. (Only very limited quantities of gaseous storage are usually allowed inside.)

    - Piping — short and direct and safe routing; high level ventilation for buildings and enclosures.
- COMPUTER ROOM — prohibition of extraneous combustibles; prohibition of smoking by room occupants; cut-off; separate air conditioning system; emergency smoke venting; smoke detection; automatic gaseous suppression flooding protective system (flood room or cabinets and below raised floor); tightly limited and isolated concentrations of combustibles or automatic sprinklers.
- CONTROL ROOM — outside wall location; emergency fresh air supply to maintain room under positive pressure; additionally, all of the approaches described in “computer room.” Keeping in mind operators need to conduct a safe shutdown.
- CABLE SPREADING ROOM AND CABLE TUNNEL — cut-off including through penetration fire-stops; emergency smoke venting; smoke detection including air sampling, early detection systems; automatic gaseous flooding protection or preaction automatic sprinklers or water spray; where all cables are in cable trays, alternate approaches are possible depending on the cable insulation.
    - BATTERY ROOM — cut-off; construction that precludes pockets of hydrogen collecting; prohibition of electrical equipment placement directly in any escaping hydrogen path; alarms upon detection of hydrogen; constant, monitored ventilation to limit hydrogen concentration to 1% in air; equipment maintenance including battery discharge tests, infrared inspections, and electrolyte testing; scheduled inspections.
    - SWITCHGEAR ROOM and RELAY ROOM — cut-off; kept free of extraneous combustibles; high level of equipment maintenance; smoke detection; emergency smoke ventilation where important for downstream power distribution; additionally:
        - Rooms containing oil-filled circuit breakers or forced ventilation needed for cooling — emergency smoke ventilation; equipment suitable for outdoor use; automatic sprinklers.
    - EMERGENCY DIESEL GENERATOR — cut-off; low lube oil and overspeed trips; alarms including high engine temperature; automatic sprinklers; fresh air supply.
    - BOILER FRONT – OIL FIRED - (including all points within 20 ft [6.1 m] horizontally, to protect potential fuel spray and flow at all levels of mezzanines and walkways) — high level of maintenance and cleanliness; baffles between oil lines and hot surfaces; oil resistant insulation near oil lines; welded piping; concentric guard piping; solid decks under oil piping; low-hazard hydraulic fluids; automatic sprinklers.
    - BOILER — combustion controls; welded repair procedures; water level alarm and backup; feedwater source and “backups”; water chemistry and steam purity controls; life extension analysis on units over 22 yrs old; also see “steam piping.”
    - FLUE GAS DESULFURIZATION UNITS — manual firefighting equipment, such as fire hoses and master stream nozzles, near access openings to the unit; fire watch when hot work is being conducted upon the unit.
    - PRECIPITATOR — temperature alarms sensing at inlet and outlet ducts; oxygen analyzer at outlet where induced draft fan is downstream; dry or less-flammable or nonflammable liquid insulated transformer-rectifier set; interlocks and dampers for automatic bypass on boiler start-up and safety shutdown; ash level indicator; plate area deluge water spray.
    - BAG TYPE FLUE GAS DUST COLLECTOR — interior partitions; heat detectors; high temperature bags; reserve supply of bags; bypass or incoming duct tempering spray; automatic sprinklers.
    - SCRUBBER HAVING PLASTIC LINER OR WALLS — automatic deluge water spray designed according to construction details, installed as temporary protection, when the scrubber module is down for maintenance, with mandatory administrative supervision during maintenance.
    - PULVERIZER AND PIPING TO BURNER — empty upon shutdown; steam or carbon dioxide flooding; examination of piping especially at bends where susceptible to erosion; thermocouple fire detection or CO monitor; deluge water spray; cool down and restart (delay) procedures.
    - REGENERATIVE AIR HEATER — instruments to monitor temperature at inlet and outlet for both air and gas flows; line-type heat detection in plates; infrared detectors; high pressure

water wash for plates; observation ports for both sides of plates; drains for washing and firefighting water; rotation speed switch; high level of maintenance on the rotation and plate cleaning systems.

- COOLING TOWER over 2000 ft^3 (56.6 m^3) — fan vibration trip and alarm; detached; lightning protection; scheduled inspections and shut-down examinations; also:
  - Combustible fill — interior fire barriers; water spray or automatic sprinklers.
  - Combustible exterior (fan deck or siding) — well detached from coal piles, buildings having combustible contents and other combustible structures or exterior water spray protection.
- FUEL OIL TANK FARM (depending on tank size and on oil classification, e.g., crude, No. 2 or No. 6) — lightning protection; tank spacing; emergency valving; yard hydrants; monitor nozzles; detachment to minimize exposure; removal of snow loads from roofs; foam systems; dikes and drains; topography selection; equipment bonding; corrosion prevention; level and temperature alarms; inspection; hazardous location classified electrical equipment (e.g., near crude oil); also:
  - Cone-roof tanks — prohibition of crude oil storage.
  - Floating roof tanks — maintenance of seals to prevent leaks and bonding between roof and wall.
  - Dikes — strainers, pumps, and filters prohibited from diked areas.
  - Pump houses, pumping stations with oil heating systems — automatic sprinkler protection or extension of tank protection.
- FUEL OIL PIPING — relief valve where there is a long run of pipe outdoors between shut off valves; minimizing exposures.
- ROOM USED FOR FUEL OIL PUMPING AND HEATING — cut-off; ventilation; approved electrical equipment; automatic sprinklers.
- GAS FUEL — prohibiting on-site storage; piping to avoid routing through storage areas.
- GAS METERING/REGULATING HOUSE — detachment; venting; hazardous location classified electrical equipment; leakage detection.
- OUTDOOR COAL PILE — detachment of 200 ft (61 m); hydrants; hose houses; ready access; precautions to minimize spontaneous combustion; tight pile compacting; ability to remove or separate burning coal.
- BELT CONVEYORS FOR COAL HANDLING (galleries and outdoor enclosed conveyors) — good housekeeping; dust collection; sprinklers under/inside all dust covers; lightning protection; maintenance on belt, roller, pulley and motor; redundancy; spare belts; low-hazard hydraulic fluid; continuous line-type detectors; tramp metal removal; less combustible type of belt; belt incline as low as possible; draft curtain; smoke/heat venting; safety shutdown on belt alignment and speed; bonds and grounds; firefighting plan of action; controlled exposures; standpipe; interlock with contributing belts and detectors; automatic sprinklers or deluge water spray.
- BUILDINGS HOUSING COAL HANDLING EQUIPMENT (thaw shed, dumper building, crusher house, transfer house, and tripper room including head house or tripper gallery but not galleries used solely for belt conveyors) — good housekeeping; dust suppression; dust collection; lightning protection; maintenance; classified electrical equipment in hazardous areas; grounds and bonds; venting; explosion venting; safe heating and cleaning (vacuum, water wash) methods; standpipe; firefighting plan of action; automatic sprinklers or deluge water spray.
- COAL SILOS, BUNKERS, AND BINS — lightning protection; venting; heat detection; explosion venting or explosion suppression; empty upon shutdown; inerting atmosphere; carbon monoxide detection; emergency dump; minimized duration of storage; dust collection.

- BAG TYPE COAL DUST COLLECTORS — located outdoors where practical; lightning protection; empty when idle; high dust level detection in hopper; fans located downstream of collector; explosion venting or suppression; shutdown interlock for fire; water spray with dust caps to avoid clogging.
- WOOD STAVES — check nearby soil for leaking; check discharged water for silt, chips and other contaminants.