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Aging Cable Assessment Guideline

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Product Description

Medium- and low-voltage cables have provided reasonable service in power plants. However, there is a concern that cables that have experienced long periods of stressed service and especially wet service might degrade and fail in service. Because most plants have had few problems with cables, little on-staff experience with cables exists at most sites. This report provides information that will be of practical use when assessing cable longevity in adverse environments and service conditions that may arise at fossil-fired plants. The report was developed as part of EPRI's Long-Term Operation (LTO) research program in the Generation Sector.

Objectives

This report is meant for persons on plant staffs who are responsible for cable system maintenance, operation, and design. This report presents currently available information on the types of cables in service in plants and the best way to address aging and monitoring concerns.

Approach

This report is unique in that it focuses on the cable types used in the power industry and the conditions that challenge them. The report supports the needs of plant staffs, allowing them to understand the specifics of their cable systems. This cable assessment should not be confused with the much broader range of cables associated with power distribution systems; these do not apply to the plants.

Results

The report provides general information on cable system design, cable construction, insulation systems, and cable aging characteristics to allow condition assessment. This practical information should help plant staffs to assess and understand critical issues about the cables and terminations that affect cable longevity.

Applications, Value, and Use

This report provides a general summary of information that can affect the aging of cables and the management of that aging. Guidance is provided on the general inspection method—depending on the cable design—and how the cable configuration is expected to degrade with time. Effects of aging of the insulation and splicing/termination system must be considered to allow appropriate selection of the inspection areas.

Keywords
Aging cable
Cable assessment
Cable insulation assessment
Cable systems
Ethylene-propylene rubber (EPR)
Medium-voltage cable

Abstract

Medium- and low-voltage cables have provided reasonable service in power plants. However, there is a concern that cables that have experienced long periods of stressed service and especially wet service might degrade and fail in service. Because most plants have had few problems with cables, little on-staff experience with cables exists at most sites. This report provides information that will be of practical use when assessing cable longevity in adverse environments and service conditions that may arise at fossil-fired plants. The report is meant for persons on plant staffs who are responsible for cable system maintenance, operation, and design. This report presents currently available information on the types of cables in service in plants and the best way to address aging and monitoring concerns.

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Section 1: Cable Environmental Stressors

The environmental and operating conditions of a cable circuit are a major factor in determining their long-term reliability. Cables operated in benign environmental conditions (dry, low ambient temperature, and low ultraviolet [UV] radiation levels) and benign operating conditions (lower voltage stress and currents lower than rated) are highly likely to function reliably well beyond 40 years. Cables in benign environments have failed in operation, but, for the most part, those failures were attributed to random defects or installation damage rather than an aging problem.

This section describes the adverse environments and operating conditions that should be understood by personnel responsible for cable system aging assessments. Knowing the adverse environments and conditions that affect cable longevity will allow personnel within a plant to identify the cable exposed to them that will have a higher likelihood of failure.

1.1 Wetted or Flooded Conditions

Historically, cable engineers mainly believed that three inherent factors were related to insulation failures: heat (oxidation), water, and time. Most power stations have been in service for several decades, and cable issues have been occurring more recently because of these stressors. Power plant duct and manhole systems that are beneath the earth's surface can become flooded. If the flooded conditions last for short periods, there will be little effect on most insulation systems. However, if manholes and ducts are prone to long-term flooding—such as ducts without a drain system or vaults without sump pumps—the cable insulation will be degraded. Energized, wet cables are likely to age from electrochemical and electromechanical actions of the water in the polymer matrix. The rate of aging is different for different insulations, semiconducting layers, and vintages of cables. Ethylene-propylene rubber (EPR) and butyl rubber cables produced before 1976–1978 are likely to age more rapidly than cables produced after that time. The aging, even in the more susceptible cables, is slow—with approximately 30 years of operation before the initial age-related failure in the population.

1.1.1 Insulation Deterioration

Conductor current can cause excessive heating if cables are operated at or above their rated ampacity (current-carrying capacity). The use of larger conductors will reduce ohmic (resistance) heating, reducing temperature and extending the life of the insulation systems. Ambient environments can be controlled by adding cooling to an area or rerouting the cable. Prolonged immersion in water was recognized as having two major reactions on underground power systems: insulation deterioration and corrosion of metal shields and conductors. These conditions can be controlled by design of the cable, constructing the duct system to remain dry, or adding dewatering systems. The length of exposure to the adverse condition will determine the ultimate life of the cable. Short or no exposure to elevated temperature and wetting will have little or no effect on cable life. Extended exposure to elevated temperature or wetting, or to both, will shorten a cable's life.

1.1.2 Design of Insulation Material

Natural rubber was the main source of insulation for medium- and low-voltage cables for power plants from 1900 to 1950. Each cable manufacturer had its own formula for rubber compounding. World War II brought polyethylene (PE) to the cable industry—first for radar cables and, just after the war, to low- and medium-voltage power cables. Electrical measurements were incorporated to show any change in properties. These test results seemed to indicate that this new material was unaffected by water. This was not the case, however, because even a small amount of moisture could deteriorate PE by creating water trees when the cable was energized for a period of time in a wet environment.

By the 1950s, researchers determined that moisture could penetrate the insulation wall of a cable if a direct current (dc) negative polarity was applied to the conductor. Test standards therefore specified that dc test sets should be constructed to impose dc negative polarity on the conductor of the cable in a test environment.

1.1.3 Water Migration in Cable Insulation

In the case of alternating current (ac), the voltage is negative for only one-half cycle. Engineers originally believed that during the positive half cycle, the water would be pushed away from the conductor. However, degradation was still noted at the conductor-to-insulation interface. This condition led to the theory that dielectrophoresis was applicable to water migration in ac cable circuits. *Electrophoresis* is a term used to describe the movement of charged particles in an electric field. Particles with a positive charge tend to move toward a negative electrode, and negative ions tend to move toward the positive electrode.

Dielectrophoresis relates to the movement of an uncharged but polarized particle or molecule in a divergent (ac) field. In the example of a single-conductor electrical cable, the field in the insulation increases as a particle or molecule gets closer to the conductor. An uncharged particle will be polarized at any given time so that it will have a negatively charged dipole with its negative side toward the conductor that is positive at that instant. Because the negative side of this dipole exists in a stronger field than the positive side, the particle will be attracted toward the field of greatest field intensity. In an ac system, as the conductor becomes negatively charged, the polarization process is reversed. This means that the particle is still attracted to the conductor with its higher electric field.

The practical effect of dielectrophoresis is that moisture is drawn to the higher dielectric field regions, even in an alternating field. This high stress point is likely to be a small void that is a portion of the initial tree formation. The void that was initially filled with gas now becomes filled with water. Although this does not fully explain the formation of the water tree, it does shed some light on the growth of such trees and the dispersion of moisture in an energized cable. Dielectrophoresis provides a way for water to propagate through the insulation to feed water tree formation, both in the insulation and at the interface between the conductor shield and the insulation. Figure 1-1 shows a poorly designed cable vault that easily fills with stormwater from the concrete yard area.

Figure 1-1
Below-grade vault in yard partially filled with water

One way to solve the problem of moisture ingress is to use a jacket or impervious metal sheath over the insulation shield system. When there is no voltage drop across the jacket, there is no dielectrophoresis effect. All of this is possible only when the jacket is intact, of course. Putting a jacket over non-shielded conductors does not accomplish this goal because the jacket material does have a voltage drop across it. Even semiconducting layers of insulation do not stop the process because there is some voltage drop across that portion of the cable as well. However, some jacket materials are better than others at preventing water passage through to the insulation. Dyed chlorosulfonated polyethylene (CSPE) jackets allow much more water transfer than do black jackets in which carbon is the colorant. Accordingly, water transfer will occur through some jacket materials without needing dielectrophoresis to cause it. This transfer occurs relatively slowly, on the order of months or more. Some of the below-grade vault in the plant will become contaminated with water, oil, and other chemicals that are part of the power production process. Figure 1-2 reveals the problem.

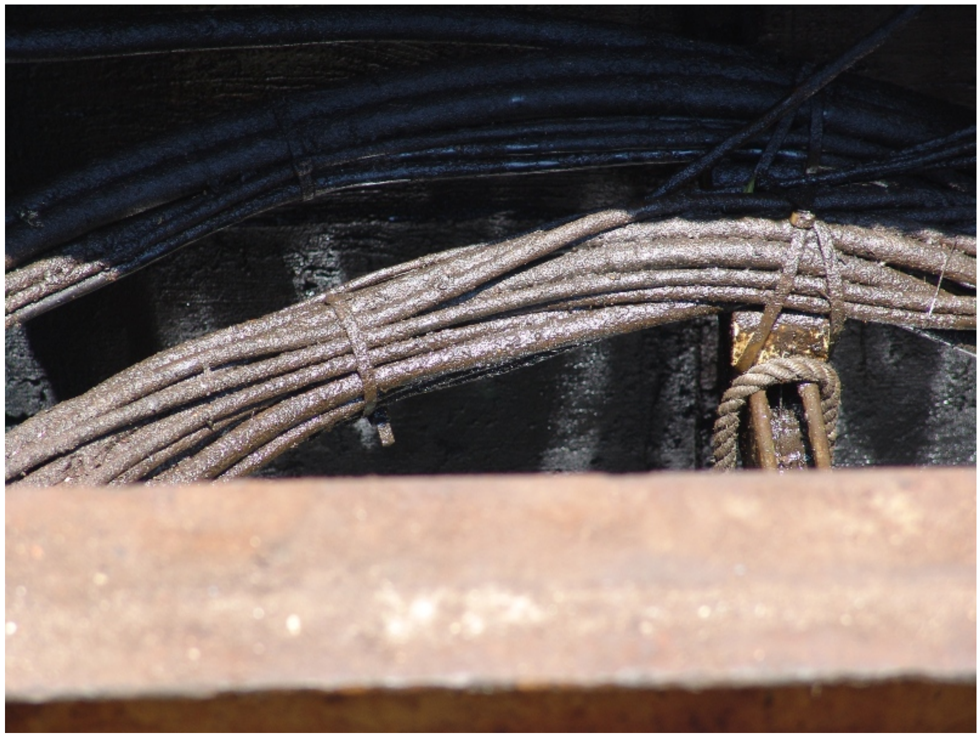

Figure 1-2
Oil-soaked cable in below-grade cable vault

1.2 Adverse Dry Conditions

Although dry cables are expected to have longer lives than wet cables, dry cable failures are possible if adverse conditions exist. These conditions can exist from the time of installation or over the life of the plant. Dry failures are often caused by random factors such as manufacturing flaws and installation damage coupled with an adverse environment or condition.

A number of physical conditions can adversely affect medium-voltage cable life, including over-bending, compression, cuts, and gouges. When a shielded cable is bent into too tight a bend radius, the insulation-to-shield interfaces can be ruptured or split—creating gaps where partial discharge (PD) can occur, which would lead to short life. Figure 1-3 is an example of tight radius bending.

Figure 1-3
Power cable tightly rolled due to excess length in prefabrication

Permanent compression of the shield and insulation system can cause elevated potential stress in the insulation or shield damage. Cuts and gouges, depending on their severity, can damage shields or even cause elevated potential stress in the insulation where cables are poorly routed as shown in Figure 1-4.

Figure 1-4
Poorly run DCS cable back-fit modification

Tension or compression forces on cables caused by routing and termination can result in mechanical damage (due to external vibration) or electrical discharge degradation (for non-shielded or single-point grounded cables). Tension can also result in failure at a cable connection point such as a splice or termination. At a minimum, performing a damage evaluation is warranted. Compression and damage to cables can occur at the dropouts from trays to local conduits. The cable should be protected from sharp edges of the conduit by a bell or other appropriate fitting, and padding might be necessary on the rungs of the tray where the cable drops out to preclude excessive load on the side of the cable.

Medium-voltage cables with larger conductors are heavy and need appropriate support devices where long vertical drops occur. Improperly supported cable can be internally crushed at its top support, leading to high electrical stress or damaged shields at the top of the vertical run. Care must be taken when following the National Electric Code requirements for supporting larger cables. The standard prescribes the same number of supports for any cable larger than 500 kcmil (250 mm^2), but if the standard were followed literally, the supports would exceed the support manufacturer's allowable weight per unit length for cables larger than 500 kcmil (250 mm^2). Manufacturer's literature should be consulted when determining vertical support requirements. If not properly supported, the weight of the cable can also pull on connections at the top of the run, possibly leading to failure. Long vertical runs should be supported by strain relief grips.

1.3 Temperature-Related Aging Conditions

Many areas and rooms inside the power plant may be relatively cool environments, less than 40°C (104°F). However, some areas that contain medium-voltage cables can have temperatures well in excess of 50°C (122°F), which could reduce the life of the cables. These areas must be identified and appropriately managed in accordance with the general guidance provided in this report. Areas near the boiler, steam lines, turbines, pulverizers, and so on may have ambient temperature in excess of 50°C (122°F) on a continuous basis, such as those shown in Figures 1-5 and 1-6. This type exposure will have a significant damaging effect on cable insulation.

Figure 1-5
Boiler inspection port exhibits extreme radiant heat

Figure 1-6
Temporary leaks of high-energy steam can degrade nearby cables

Consideration to those vents with high temperatures is also necessary. Most often ignored are large-motor air slot outlets. These motors are also air-cooled through their stators, and the air exhausted is often in excess of 50°C (122°F). The motor leads and the stator heater leads are often routed through this air stream and results in a long-term "baking" of the leads. Examples of good and poor cable routing are noted in Figures 1-7, 1-8, 1-9, and 1-10.

Figure 1-7
Properly routed power cable not in heat exhaust

Figure 1-8
Power cable properly routed away from heat vents on 48-year-old motor

Figure 1-9
Junction box leads poorly placed immediately below the discharge vent hood

Figure 1-10
Junction box and leads poorly designed in exhaust flow

Heavily loaded cable trays with cables near their maximum ampacity will generate heat that may become trapped in the cable bundle and create a self-generated heat source that will degrade the cable insulation. Depending on the original construction specifications, the maximum loading per cable may be as high as 100% of its capacity for the distance run. In addition to the ampacity for full load, the number of cables per tray may be at maximum or higher, causing self-induced heating and loss of heat rejection capability.

1.4 High-Resistance Connections and Splices

Improperly made splices and terminations can deteriorate from elevated temperatures resulting from the high-resistance connections. Terminations that are separable and not properly reassembled (can be verified by thermography, if accessible) are also candidates for thermal degradation over time due to high connection resistance. These conditions, if not identified and corrected, will thermally degrade the cable insulation or splice over time.

1.5 Surface Corona and Partial Discharge

Non-shielded cable can be subject to surface PD (corona) in the small gap adjacent to the location at which the cable touches a grounded metal surface. Corona discharges occur from ionization of the air gap between the cable and the grounded surface. The conductor voltage distributes across the insulation, jacket, and air gap, with a large portion of the voltage across the air. With high voltage across a small gap, voltage stress higher than the breakdown stress of the air occurs. The gap discharges, and the voltage redistributes across the insulation and jacket so that the discharge is stopped. However, each electron stream discharge causes a small increment of damage to the polymer surface, resulting in erosion of the polymer. Over an extended period, these discharges can erode the surface of the cable's jacket and continue to slowly reduce the dielectric strength of the insulation system. In such cases, the presence of corona discharge is often indicated by a white powder in the vicinity of the discharge. Corona attack can be identified by visual examination during maintenance when terminations and junction boxes are accessible. An example of corona discharge is shown in Figures 1-11 and 1-12.

Figure 1-11
Corona discharge indication on a cable and ground

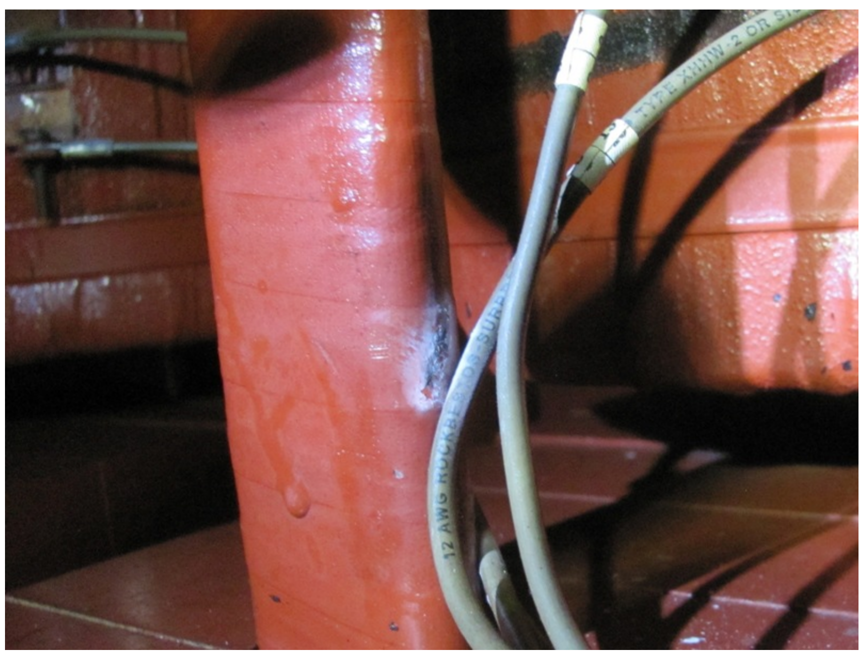

Figure 1-12
Partial arc indication on current transformer cable and phase bar of a 13.8-kV motor

1.6 UV Damage to Cables

Many people overlook the presence of UV light on cable surfaces. Most fossil-fired stations have cable trays running in unenclosed areas exposed to sunlight. Here the effects of sunlight will become apparent. Most design engineering firms have these trays covered to protect them not only from the weather, but also from sunlight. The problem occurs when workers have to access the trays and do not re-cover them with tray covers. UV light can be generated by sunlight and by artificial light. UV can cause damage to the backbone of the polymer, reducing the properties of the material. If the rubber component is of non-black formulations, the UV can affect the color and cause a minor to major change in the color. Carbon black–filled rubber components are much less susceptible to UV because the black helps to absorb the UV light and stabilize the product. The best condition would be to protect the cables in a low light area or in a covered cable tray or conduit. When strong lighting is added to the interior of stations, it may inadvertently increase the exposure of the unprotected cables to UV light and degrade the surfaces (many of these strong area lights also emit UV radiation). Note the poor condition of the cable tray covers on this outdoor unit in Figure 1-13.

Figure 1-13
Missing cable tray covers expose cables to UV radiation in sunlight

Section 2: Assessment Preparation

Properly preparing for an assessment of the station's cable condition requires knowing what cables are in the field and their past performance. Many older stations do not have sufficient records to document the type of cable and any calculations that support its use. If this is the case, cable inspections may have to start with identifying the manufacturer, size, and type. Once this has been established, the extent of inspection and locations will become the next challenge.

2.1 General Design

In general, most plant cable systems are believed to be less susceptible to moisture-related degradation because of their low electrical stress levels and the use of rubber insulations, overall jackets, duct bank systems, and well-shielded terminations. Shielding the terminations from lightning strikes removes a significant source of severe voltage surges that can cause failure or initiate electrical treeing in deteriorated cable. Most power plant circuits are terminated inside buildings or sheltered areas so that they will not be exposed to lightning strikes. Medium-voltage cable systems have operating voltages in the lower band of the medium-voltage range, where the electrical stress is lower than in the upper band of the medium-voltage range. This lower voltage stress causes electrical-related degradation to occur more slowly than in cables operating at 35 kV and greater. Much of the literature on cable insulation aging relates to the aging of wetted cable systems that are more prone to electrical failure. It is less applicable to the majority of stations because they have rubber insulation systems.

2.2 Medium-Voltage Cable Constructions

Underground medium-voltage cables at plants are installed as one of three basic cable assembly configurations:

- Individual, insulated single conductors
- A twisted combination of the insulated single conductors, known as a *triplexed assembly*
- A jacketed three-conductor cable

In any of these assemblies, the insulated conductors share the same basic construction shown in Figure 2-1, with the exception of the jacketed three-conductor cable—which has an overall jacket over the insulated singles.

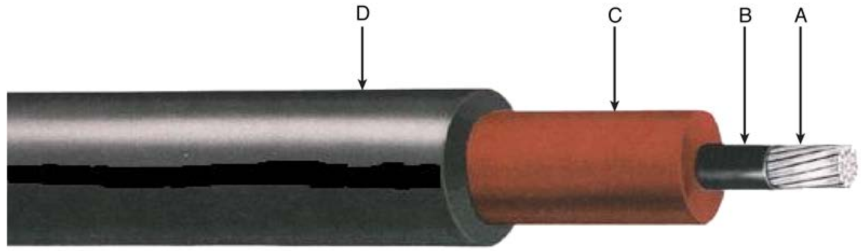

Figure 2-1
Medium-voltage non-shielded cable design

Figure 2-1 shows a non-shielded cable design. In this design, there is no insulation shield. This design has been applied in many instances for medium-voltage circuits of 4160 V and lower. The reason is that non-grounded systems, when designed properly, can tolerate a single phase-to-ground fault while remaining in service for a short period. However, the absence of a shield that confines the voltage stress to the insulation makes testing of the insulation system in a meaningful way quite difficult. Testing is possible in a laboratory by submerging the cable in water and using the water for the ground plane. Submergence of an entire circuit is not practical in a plant and can provide confusing results because the jacket of the cable is in series with the insulation and can affect the test results.

2.3 Develop a Critical Component Inspection Plan

In developing a critical component inspection plan, select the component whose immediate loss would result in significant loss of generation. This allows the selection of the power cables of most interest. The objective is not to develop a test program, but to perform a visual inspection of critical cables in their operating environment. Based on past performance, the inspections will provide additional confidence in the remaining life of the cable system.

2.4 Critical Cable List

Critical components are those that seriously limit the unit's ability to maintain near-full-load conditions: these components' power supply cables should be inspected. Included with this are all power supply systems within its supply chain—that is, the bus system supplying this power cable to the extent that it is within the unit's internal bus system.

2.5 Priority

Selection of order of inspection should be based on highest stressed cables: those operating near their ampacity and cycling most often. Check the loading based on full-load running current of the load, the cable rating, and operators' knowledge of how often the cable is cycled.

2.5.1 Safety

The component should not be operating when these inspections are performed. Arc flash safety is a concern when opening junction heads on large motors and breaker cubicles. Therefore, the unit should be in an outage for best-practice inspections. Touching and moving cables may cause failures; therefore, all hands-on inspections should be on deenergized components, using energy control processes (lock-out/tag-out).

Section 3: Inspections

This section presents a recommended inspection procedure if the station needs one or has not created one for its particular situation. It is simplistic and does not provide specific safety requirements for the station; users should enhance if for plant specifics. The intent is to create a report of all specific locations and at-risk cable systems. Therefore, a document-creation process should be used that identifies each cable and uniquely lists it in the report for future reference.

3.1 Based on prioritized inspection locations, locate cables via trays, conduit closures, junction boxes, and lead connection boxes.

3.2 Open the enclosure, and inspect the interior for possible partial discharge indications.

3.3 Continue the inspection by visually inspecting the cable phases for the following:

- 3.3.1 Cracking.
- 3.3.2 Discoloration.
- 3.3.3 Burns.

3.4 Document findings.

3.5 Carefully bend the cable nearest the connection point, looking for jacket cracking.

3.6 Document findings.

3.7 Using a sharp-edged tool or fingernail, attempt to indent the cable nearest its connection. Move back as far as possible from this point (at least 18 in. [457 mm]), and retest the cable to determine whether any hardening has been occurring near the load.

3.8 Open cable vaults in the yards, and perform inspections.

- 3.8.1 Determine if there is evidence of past flooding, for example:
  - 3.8.1.1 Standing water and/or oil.
  - 3.8.1.2 Mud or sand.
  - 3.8.1.3 Waterline evidence.
  - 3.8.1.4 Organic growth.
- 3.8.2 Observe for oil or water damage on the cables, as evidenced by:
  - 3.8.2.1 Cracking.
  - 3.8.2.2 Discoloration.

3.8.3 Document the as-found conditions. Prevention may not be possible without significant design changes to the underground cable vault and trenches.

3.9 Inspect cable trays exposed to sunlight:

3.9.1 Are tray covers missing?

3.9.1.1 If so, are cables exhibiting signs of UV deterioration, such as discoloration or cracking?

3.9.1.2 Write discrepancy reports (work requests) to have tray covers replaced.

3.10 Conduct hot-spot inspections:

3.10.1 Using plant knowledge, inspect general hot spots where cables are in close proximity, such as:

3.10.1.1 Boiler area.

3.10.1.2 Pulverizer area.

3.10.1.3 Turbine area.

3.10.1.4 Ash handling area.

3.10.2 Document findings.

3.10.3 Write discrepancy reports (work requests) to have insulation, shield, and so on returned to their locations to reduce radiant heating of equipment.

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