ELECTRIC POWER RESEARCH INSTITUTE

Low-Voltage Cable Aging Management Guidance

2013 TECHNICAL REPORT

Low-Voltage Cable Aging Management Guidance

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Report Summary

This report, intended for use by power plant engineers and craft and administrative personnel who are responsible for cable system aging management, provides guidance on the effective and efficient application of current information and techniques related to aging and condition monitoring (CM) of low-voltage cables. The identification of cables that are prone to early aging and the timely replacement or repair of cables that are degraded will minimize unnecessary power losses, unplanned shutdowns, and challenges to plant safety and environmental compliance systems.

Background

Over the last two decades, numerous reports have been written that provide part of the basis and insight for the development of a cable system aging management program. None of them, however, describes a complete or concise basis for such a program. This report integrates key information from important references to make the concepts of cable aging management easy to understand.

Objectives

- To develop a report that helps all personnel involved in cable system aging management to efficiently and effectively apply the cable aging, aging management, and CM information that has been developed over the past 20 years
- To assist industry personnel in identifying when CM is necessary and which CM technique is appropriate for given cable configurations and materials

Approach

The immediate and long-term needs of plant personnel were identified through discussions with utility representatives. Existing reports were researched, and the information was condensed and refined so that the essential topics could be presented in brief sections in this report. Sources of more detailed information were gathered and have been included for use as needed. Photographs from different installations, which illustrate various cable aging conditions, were also collected and are presented in an appendix.

Results

This report presents brief and concise summaries of the most current technical knowledge and best plant practices related to cable aging management. This information will enable a person with no previous experience in cable aging to become familiar with the best methods that can be used to identify the cables in a plant that are most likely to age and the CM techniques that can be applied.

Applications, Value, and Use

The concepts presented in this report will enable plant personnel to develop a formal cable system aging management program. Primary aging mechanisms, concerns, and issues are described along with basic cable design. Key insights into actual problems and resolutions that have occurred in operating plants are presented. Information necessary for understanding degradation and its importance is provided in the most concise manner possible. For personnel interested in more detail, references to the base information are provided. This report provides sufficient information to enable personnel to readily understand cable system aging management and the activities that must be performed to control the aging of cables during remaining plant life.

Keywords

Cable management
Condition monitoring of cable
Electrical cable aging
Instrumentation and control cables
Low-voltage electrical cables

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Section 1: Introduction

This report will assist engineers and craft and administrative personnel who are responsible for cable system reliability in the effective and efficient use of the cable aging and condition monitoring (CM) information developed over the past 20 years. Numerous documents containing a variety of cable aging information have been published previously; this report collects the information from the published research and presents it in a simple-to-use format. Many references and detailed information are included throughout the report.

The report will help the user to determine when and where aging is occurring and to suggest appropriate remedial action. A good understanding of cable aging characteristics, and the operational and environmental conditions that could affect these characteristics, is a prerequisite for assurance of the long-term reliability of cables. This report provides the basis for understanding cable aging issues. Assessment of cables that are prone to early aging, and the timely replacement or repair of degraded cables, will minimize unnecessary power losses, unplanned shutdowns, and challenges to plant safety systems.

A simple cable contains two parts—the metal conductor and the nonmetallic insulation that covers the conductor. A more complex cable can contain several conductors, fillers, a wrap or shield, individual conductor jackets, and an overall jacket. The metal conductor, wrap, and shield are not normally evaluated for aging.[1] Thus, the insulation and jacket(s) are usually the focus of aging management, with the aging of the insulation being the most significant factor.

As cable insulations and jackets age, they can:

- Become harder or softer
- Become shiny or dull
- Change color or hue
- Remain as they appeared originally
- Crack spontaneously if severely aged (polyvinyl chloride [PVC], neoprene)

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[1] Conductor corrosion and damage does occur, even though relatively rarely. There is little concern for conductor aging in dry areas (that is, the bulk of the plant). However, moist areas, such as the intake structure, and chemical areas, such as borate- and water-treatment rooms, might have problems and should be considered for inspection. Also, areas with neoprene and a high temperature might generate chlorine, which can cause conductor corrosion, especially in moist areas.

The low overall failure rate for cables observed during commercial power plant operation in the United States indicates that:

- Cable systems experience a low rate of failure
- Bulk cable system aging is generally not of concern
- Most circuits are not subjected to significant localized aging influences with respect to capabilities of the insulations and jackets

There are, however, cables installed in certain limited plant areas or applications that are subject to relatively rapid aging.[2] These cables can be identified by:

- Reviewing plant condition reports and historical data for evidence of past cable failures
- Identifying hot spots and wear-aging conditions that are common to all plants
- Evaluating information obtained by systematic review of cable system layout drawings, walkdowns, temperature monitoring, thermography, and interviews with long-term employees in the crafts

The most important part of cable condition monitoring is a walkdown inspection. The inspection should focus on plant areas with adverse environments and should identify the environmental conditions in the immediate vicinity of the cables. Although a walkdown of the entire plant could be beneficial, it is not necessary in those areas that are known to have mild environmental conditions. A walkdown, with visual/tactile inspections of cables, should be performed in those areas known to be hot so that an evaluation can be made as to whether or not significant aging degradation is occurring and whether corrective actions need to be taken. Detailed guidance and helpful examples for performing walkdown inspections were prepared by utility representatives and are presented in EPRI report TR-109619 [1]. The use of visual/tactile assessment is described in EPRI report 1001391 [2].

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[2] All cables are aging, but some of them are aging very slowly. For these cables, advanced aging will not occur before the end of plant life. Some cables are aging relatively rapidly, and their useful life will be expended prior to the end of plant life.

Section 2: Steps to Cable Aging Management

This report is structured so that the reader is presented with a sequence of topics that provide a concise summary of the most current information pertaining to the aging of cables. The chapters are arranged to answer the following five questions:

- What causes cable aging?
- How can the cables most likely to age rapidly be identified?
- Where are those cables located?
- What CM methods can be used to determine the amount of aging that has occurred?
- How can cable service conditions be evaluated so that personnel can modify the conditions that cause aging?

The sequence of the chapters was established so that a person who is not familiar with cable aging can read through a step-by-step presentation of information essential for cable system aging management. Each chapter also contains numerous references to other EPRI reports so that more detailed information on the topic can be obtained, as desired.

In addition to the specific topics discussed in each chapter, there are three additional collections of useful information. Appendix A contains a table of previously identified causes of cable aging problems along with text providing additional details and pertinent operating experience, and Appendix B contains photographs of cable aging-related conditions. This information is presented to both enhance and illustrate the topics in the chapters. The reader can examine the photographs in Appendix B before reading any of the text to understand various aspects of cable aging and be prepared for concepts provided by the text. Appendix C provides an understanding of the design of low-voltage plant cable systems.

The table and explanatory text in Appendix A are designed to provide information and recommendations concerning 17 specific cable aging problems that have been identified over the last 35 years of power plant operations. Although Appendix A can be used independently from any of the chapters to resolve aging problems, it can be used more effectively after reading all of the chapters.

Section 3: Causes of Cable Aging

Aging of low-voltage cables is caused by exposure to the following three stressors:

- Heat
  - Ambient room temperature
  - Localized high-temperature or radiant heat (hot spots)
  - Ohmic heating (power cables only)
- Manipulation (generally at terminations from work on associated equipment)
- Wetting (primarily a concern for crimped terminal connections or terminal blocks in wet and salt-air spaces. This is a conductor/termination interface concern and not an insulation concern.[3])

Heat

Thermal aging results from the exposure of cable materials to normal and abnormal thermal environments. The normal ambient room temperature in most plant areas results in very slow degradation of cable insulation and jacket materials. However, localized elevated temperature or radiant heat from sources such as process lines that are too close, or inadequate ventilation (dead air spaces), can produce severe damage relatively rapidly. Generally, the damage is limited to one portion of the cable. Elevated temperatures resulting from thermal stratification in the ambient air volume can age large sections of cable that are located at higher elevations within an enclosed space. Aging of insulation can also result from ohmic current heating of cable conductors if an undersized conductor is used or if the combination of ambient temperature and ohmic heating is not properly considered for the application.

Hot spots (or adverse localized equipment environments), as described in EPRI report TR-109619 [1], affect only limited portions, if any, of a given cable run. Nonetheless, they are a major concern because the rate of material degradation (embrittlement that can lead to cracking) within the hot spot can be significantly higher than that occurring everywhere else; loss of normal and/or accident

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[3] Wetting of cable insulation and jacket materials is generally not a concern unless simultaneous high-temperature conditions exist that could cause chemical breakdown of the materials (that is, wetting is not a concern as long as the cables are not being cooked in the liquid).

functionality might occur if not corrected. The rate of degradation is dependent on the nature of the cable materials, the intensity of the heat source and the cable's proximity to it, and the existence of any mitigating factors such as shielding or ventilation.

Ohmic (I^2R) heating, resulting from electrical current (amps) in power cables, generally affects the entire length of a cable run, with the most adverse effect in locations that have ambient environment hot spots or poor heat transfer (such as might occur in some fire barriers). As current (I) flows through a conductor, heat is generated by the resistance (R) of the conductor. The rate of heat generation in a cable is related to the ampacity (design current carrying capability) of the cable (I^2R is directly proportional to current and indirectly proportional to conductor size). The higher the actual current in relation to the cable ampacity, the greater will be the rate of heat generation. Thermal aging that results from conductor ohmic heating is significant in power cable applications where the connected load is operated for a significant percentage of its installed lifetime, and the current during such operation is a substantial percentage of the ampacity of the cable.[4] Intermittently operated, low-duty factor loads (even at high current) typically will not result in substantial aging of the connected cable. Similarly, loads that are run continuously, but whose operating currents are low in relation to the ampacity of the cable, will result in little cable aging.

Manipulation

Wear aging of cable system components pertains only to terminations and/or connections and results primarily from manipulation (bending) of the component during maintenance or testing. Because most field cable is never disturbed or moved after it is installed, little or no wear is expected. However, cables can be damaged as a result of climbing if that has been a practice.[5] However, for some terminations (for example, multi-pin connectors that are frequently disconnected and reconnected for maintenance, inspection, or periodic surveillance testing activities) wear (fatigue) can be a significant aging mechanism for the ends of cables that are attached to the terminations.

The manipulation of cables can also result in cracking and, possibly, the exposure of bare conductors in cables that have embrittled insulation or jacketing from severe thermal aging. Such aging causes the elongation-at-break and tensile strength to be very low. As the cable is bent, the outer radius of the jacket or insulation is placed in tension; if the bend is of a sufficiently small radius, the elongation capability of the aged material can be exceeded and rupture can occur. For jacketed cables, the jacket can age more rapidly than the underlying

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[4] The issue of local hot spots caused by clusters of power cables in trays or conduits is not addressed in this report. The size, number, placement, and ampacity de-rating of power cables in a tray or conduit has been based on design guidance (such as the National Electrical Code and individual plant specifications). Analysis and consideration of the effects of local heating in trays and conduits are beyond the scope of this report.

[5] This type of wear is different from incidental mechanical damage, such as that resulting from work in the immediate vicinity or from personnel traffic.

insulation, thereby more readily rupturing under sufficient bending stress. If cable jackets or insulation are found to be hardened or resistant to flexure, they should not be bent further. The cause of the hardening and the need to replace the cable should be considered immediately.

Wetting

Insulation thicknesses are so large—30 mils of insulation requires 20,000 to 90,000 Vdc to cause breakdown, while low-voltage cables operate at 600 Vac and less—that the voltage stress in the insulation is insufficient to cause water and electrical treeing. However, in some cable applications, the combination of voltage and moisture can affect insulation that is dirty or deteriorated, thus resulting in surface tracking paths at terminations[6] between conductor and ground, or conductor and conductor. For such conditions to occur, the physical arrangement of the termination must be such that the electrical distance between the conductor and ground or another conductor is not large, the surface is wet and retains the moisture, or the surface is contaminated with a conducting material, or a material that supports moisture paths. This condition can result in localized burning of the insulation and carbonization at the ends of the tracking paths and, ultimately, in insulation failure. A condition called dry banding can be a problem for circuits in moist areas that cycle. In dry banding, the moisture that bridges the conductors begins to evaporate as the leakage current heats the liquid. The current flows through a smaller and smaller band of moisture until, just as the last of the moisture evaporates fully, a very high current density is flowing through a very narrow band of moisture. The heating in the narrow band is intense, which causes significant damage with each energization. The sealing of junction boxes and inspection of circuits in moist areas will preclude such problems.

Summary of the Causes and Effects of Cable Aging

The effects of severe aging degradation of cable materials can include embrittlement, cracking or crazing, discoloration, melting, and a change in the mechanical and electrical properties that are essential for the cable to perform its design function. A summary of all aging stressors, observed aging mechanisms, degradations, and potential effects of aging on the components of a low- voltage cable system is presented in Table 3-1. This table is taken from a comprehensive study of cable aging published in SAND96-0344 [3].

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[6] Tracking can occur as cuts in the insulation are subjected to moisture or electrically conductive contaminants.

Table 3-1
Summary of Stressors, Significant and Observed Aging Mechanisms, Degradation, and Potential Effects[7]

Component	Subcomponent(s)	Applicable Stressors	Aging Mechanisms	Degradation	Potential Effects
Cable	Insulation and jacketing	Heat, oxygen	Thermal and thermo-oxidative degradation of organics from ambient and ohmic heating	Embrittlement, cracking, melting, discoloration	Reduced insulation resistance (IR); electrical failure; increased vulnerability to failure in harsh environments
		Oxygen	Chemical decomposition of organics	Embrittlement, cracking, discoloration, swelling	Reduced IR; electrical failure
		External mechanical stresses	Wear resulting from work in area, personnel traffic, or poor support practices	Cuts, cracking, abrasion, tearing	Reduced IR; electrical failure
Connector	Contact surfaces	Electrochemical stresses (moisture, oxygen, and so on)	Corrosion and oxidation of metals	Corrosion and oxidation of external surfaces of contacts	Increased resistance and heating; loss of circuit continuity
Compression fitting	Lug	Vibration, tensile stress	Deformation and fatigue of metals	Loosening of lug on conductor; breakage of lug	Loss of circuit continuity; high resistance

[7] Adapted from Table 4-18 in SAND96-0344 [3].

Section 4: Methodology Used to Identify Cables Most Likely to Age Prematurely

The failure of one or several cables could require the plant to shut down if the failure interrupts a circuit whose operation is essential to normal plant operation. To identify those cables most likely to experience failure from aging, a methodology based on known failure causes has been established. The list of cables identified by this process establishes the subset of plant cables that has the greatest possibility of failure prior to the end of plant operating life.

Cables that are most likely to age rapidly and fail can be identified by using the following three- step process:

1. Identify short-lived cables based on thermal calculations (Arrhenius method described in EPRI report NP-1558 [4])
2. Identify short-lived cables based on factors that cannot be included in an equation. Analyze computerized maintenance and work order records and databases, using key words to select cables that:
   - Have failed previously
   - Have exhibited the effects of aging (appearing hard, discolored, cracked, and so on)
   - Have been disconnected and reconnected numerous times
   - Are located above (or close to) steam or hot process fluid lines
   - Are located in dead air spaces or areas that can trap heat
   - Are located near sections of insulation that have been removed or replaced repeatedly
   - Are connected to valve operators (solenoid-operated valves [SOVs] and motor-operated valves [MOVs]) and motors that have required frequent maintenance, repair, and/or replacement
3. Obtain anecdotal information from craft personnel who have identified the deterioration of cable from service conditions. (These personnel might not know the cause of deterioration but can identify applications that need to be assessed for aging management.)

An overall analytical process that can initially be used to identify cables that would be most likely to age prematurely consists of the following six steps:

1. Determine the types of cables installed (insulation and jacket materials), perhaps from procurement and/or construction records.
2. Identify the environments (thermal) to which the cables will be subjected during normal operating conditions.
3. Establish the service conditions (normally energized/de-energized, load cycle).
4. Assess expected lives (thermal) of cable materials based on the worst-case environment and worst-case applications.
5. Identify adverse environment spaces in the plant where any of the cable types have short lives (1.5 times the plant age at the time of the assessment).
6. Determine if cables with short lives were actually used in the adverse environment spaces.

A detailed example of the methodology is presented in EPRI report TR-106687 [5]. Specific sections of interest from that report include the following.

Calculating Thermal Life, Part One, Section V, page 1-5-1

The Arrhenius method, described in EPRI report NP-1558 [4], provides a relationship between material lifetime and physical stress (temperature), and the formula can be used to calculate thermal life. The three types of required input data include the activation energy and intercept values (obtained from a standard accelerated thermal aging test), and the temperature to which the cable materials will be exposed during normal operations. Material-specific data concerning thermal life resistance can be obtained from Tables 9-1 and B-3 in EPRI report 1003057 [6].

The Arrhenius Model (EPRI report TR-106687 [5]):

$$\mathrm{Log}_{10}\, L = \phi\,(5040)/T + b$$

where:

L = life (hours)

ϕ = activation energy in electron volts (eV)

T = material temperature (K)

B = mathematical “intercept”

This form of the equation can be used to calculate the total thermal life of any cable insulation.

Search Computerized Maintenance Management Work Orders, Part Three, Section IV, page 3-4-1

Search the plant databases using key words that describe the effects of cable aging. The key words must be representative of words that craft personnel would use to describe the effects that they observed. Examples of such key words that have produced good results in previous searches include *cable*, *age*, *aging*, *heat*, *insulation*, *brittle*, *discolored*, and *hard*.

Interviewing Craft Personnel, Part Three, Section IV, page 3-4-4

Conduct interviews with several long-term craft personnel (electricians and maintenance personnel) to obtain both anecdotal information and their perspective on the general historical performance of the plant cables. Such interviews do not take much time, and the information obtained concerning operating experience can be highly beneficial in determining the need for a condition monitoring program. Each person should be interviewed separately. A sample list of questions that might be helpful during the interviews is contained in Section 4.4 of EPRI report 1003317 [7].

Application of the methodology produces a list of cables at risk of aging at a given time, but the list is not static. Because the environments for cables can be different than those assumed for calculating thermal life, or can change as a result of various conditions that place cables at risk for accelerated aging, the list should be expected to change in the future. Any initial list must be reviewed periodically and modified as appropriate, especially in the case where duty cycles change.

A plant should review the list of cables to identify those:

- That are important to plant operation, environmental compliance, and safety
- Whose failure might cause a trip
- Whose failure during operation could cause an extended outage because of their installed location (as compared to the time it would take to replace the cable as a planned preventive maintenance task)
- That could cause a plant trip or significant reduction in plant output for a significant duration

Even if both the analytical process and the interview process indicate that there are no cables with short lives, best-practice engineering still suggests that a walkdown and visual inspection should be performed for at least a few of the cables that have the highest likelihood of early aging (such as heavily loaded power cables installed in high-temperature areas).

Section 5: Common Hot Spots or Wear-Aging Conditions

Experience at many plants has shown that cables can age much more quickly than would otherwise have been expected because of the following six conditions occurring in the vicinity of cables:

- Elevated surface temperature of insulated pipes
- Missing pipe insulation or gaps in the insulation
- Valve operators and other devices on steam or hot process lines
- Continuously energized SOVs
- Localized high-temperature areas
- Manipulation of aged cables

Surface Temperature of Insulated Pipes

Although the maximum general area temperature for a given space might only be 95°F (35°C), the surface temperature of the insulation on a steam pipe can be as high as 150°F (66°C). Cables located in trays installed directly above a large group of steam or hot process fluid lines could therefore be subjected to a continuous temperature that is much higher than the general area temperature.

Missing Pipe Insulation

Insulation on steam lines must be removed occasionally to allow access for maintenance or surveillance activities, or for design modifications. If it is not replaced properly, the result will be a higher local ambient temperature than was anticipated in the general space HVAC design. Cables located close to the improperly replaced insulation can age much more quickly than the rest of the cable run because of either thermal convection or radiant shine. Rapid aging will also occur when cables are directly adjacent to gaps in the insulation on hot pipes, boilers, valves, and heat exchangers (for example, blankets that do not completely overlap). For insulation with an external sheath, subsurface gaps might not be obvious through visual inspection. Assessment by the use of infrared camera might be necessary.

Areas where such hot spots could exist can be identified by a computer search of completed maintenance or repair work orders, using key search words such as *insulation*, *remove*, *restore*, and *replace*. Any piping area for which these words appear repeatedly over a period of several outages should be cross-matched with the conduit and cable schedule. A visual/tactile inspection of cables in those locations can then be performed to obtain an initial assessment of cable condition.

Valve Operators and Other Devices on Steam or Hot Process Lines

The metallic bodies of some valve operators are installed directly in-line in steam or hot process fluid pipes. Because there is no thermal isolation between the pipe and the operator, heat is conducted through and along the operator body. Cables entering the valve operator can be subjected to temperatures that are much higher than those assumed for the general area, and the cable materials at the point of contact will age much faster than the cable material only a few feet away.

Continuously Energized Solenoid-Operated Valves

Field cables that are directly connected to normally energized SOVs can degrade at an accelerated rate at the point of connection to the SOV because of the heat generated by the SOV coil. The field cables for applications with extended leads that have high-temperature insulations are protected from the coil heat. However, the high-temperature leads should be assessed occasionally to confirm that they, too, are in acceptable condition.

Localized High-Temperature Areas

General plant areas can have localized temperatures that are higher than the bulk design temperature because of inadequate ventilation (dead air space) or the installation of heavily loaded, continuously operating equipment, such as a pump motor. Also, design modifications can result in the addition of heat-producing equipment, so that cables that were previously considered to be installed in areas associated with no significant aging begin to age more rapidly.

The human body is a good temperature sensor for detecting local high-temperature areas. Craft personnel are constantly working in various areas throughout the plant and know from experience where it is hot. A brief personal interview with long-term employees in the various crafts will provide a good basis of knowledge concerning hot local areas in the plant. Combining those locations with cable locations will pinpoint potential areas for localized accelerated cable aging.

Plant areas that are known to have high localized temperatures include the following:

- Main stop valves (MSVs)
- Boiler burners
- Boiler dead air spaces

- Under high-pressure/intermediate-pressure (HP/IP) turbines
- Electrical cabinets
- Drums, heat recovery steam generators (HRSGs), and pulverized coal (PC) boilers
- High-power, incandescent lighting fixtures (see Appendix B, Figure B-3)
- Expansion joints
- Pulverizers
- Safety valves
- Air preheaters

Manipulation of Field Cable Terminations

Cables that are regularly connected and disconnected from equipment during outages can be wear-aged at the termination as the result of mechanical manipulation. Insulations and jackets that have been severely thermally aged are susceptible to cracking if manipulated. For the following examples of equipment, plant maintenance involves the manipulation of cables:

- Instruments that must be removed to access equipment for maintenance and/or disassembly
- Instruments that must be removed for recalibration
- SOVs and motors that are replaced (or repaired) regularly because they are continuously energized

Using key search words such as *remove*, *calibrate*, *replace*, and *reinstall*, identification of these cables can be established quickly by a computer sort of completed maintenance and work orders for the last several outages. Equipment ID numbers that are listed in each outage can then be correlated with the cable number to identify cables that are subject to aging from manipulation.

Section 6: Condition Monitoring

Methods Available to Evaluate Cable Condition

A number of diagnostic techniques have been developed that enable assessment of the functionality and condition of power plant cables. Some of these techniques are useful in evaluating installed cables, and others are destructive tests that must be conducted with samples of cable materials removed from service. Some of these methods are useful for trending the long- term performance of cables, and others are primarily useful in troubleshooting. The remainder consists of laboratory tests used to characterize the properties and performance of specific cable materials. Some of the diagnostic techniques have been demonstrated and reduced to practice. Some are nearing readiness, and a few are in the development stage and show promise.

Troubleshooting tests are generally only performed in the event of problems with a circuit. Such tests are not routinely performed because of the time and difficulty involved in de-terminating cables, and the fact that they show current functionality but do not indicate the degree of aging of the insulation system. Most electrical tests for insulation are troubleshooting tests. Insulation resistance (IR) testing is a typical troubleshooting technique used by plant operators to confirm or localize suspected or known problems; however, IR tests do not detect insulation damage or other circuit degradation prior to very severe deterioration. For low-voltage cables, even a small thickness of undamaged insulation can provide sufficient dielectric strength to prevent the detection of degradation by these tests. Additional guidance on common electrical test methods used for troubleshooting is presented in EPRI report TR-106108 [8].

Condition monitoring tests are used to trend or assess the condition of cable materials with respect to aging. Currently available techniques can be classified as either nondestructive or destructive. Nondestructive techniques have no deleterious effect on the cable under test, but relatively few nondestructive tests are available. Destructive techniques destroy the material under test. With destructive techniques, a section of cable or its polymer layers must be removed from service and sent for laboratory testing. Early destructive tests required large sections of cables (for example, 6 inches [152 mm] or more per test) and if insufficient slack existed in the cable to allow retermination, replacement of the cable would be required to allow for condition testing. Replacement of the cable to establish its condition is generally unacceptable unless the cable is representative of a large population of cables subjected to similar conditions. Because many of the destructive tests are highly useful for assessing condition, methods using very small specimens (that is, milligrams) have been developed. These small-specimen lab tests require very small samples to be removed from in-service cables. Some repair work to the surface of the insulation or jacket will also be required in most cases.

A cable aging management guideline that was prepared for the Department of Energy (DOE) is SAND96-0344 [3], which includes a comprehensive list of CM and aging management methods for cables. Each method was evaluated and analyzed for use in either the field or in the laboratory, and is described in detail. Tables 6-1 and 6-2 list the methods applicable to low- voltage cables.

Table 6-1
Condition Monitoring Methods for Low-Voltage Cables

Method	Destructive	Nondestructive	Small Specimen
Compressive Modulus (Indenter)		X	
Density			X
Nuclear Magnetic Resonance			X
Elongation-at-Break (EAB)	X		
Fourier Transform Infrared (FTIR)			X
Gel Content*			X
Oxidation Induction Temperature (OITT)			X
Oxidation Induction Time (OIT)			X
Plasticizer Content (PVC Only)			X
Tensile Strength	X		
UV Spectroscopy			X

* Accuracy increases with larger specimens.

Table 6-2
Troubleshooting Methods for Low-Voltage Cables

Method	Destructive	Nondestructive	Small Specimen
Capacitance		X	
Insulation Power Factor (PF)		X	
Insulation Resistance (IR)		X	
Polarization Index (PI)		X	
Tan Delta		X	
Time Domain Reflectometry (TDR)		X	

Best Available Condition Monitoring Methods

Condition monitoring, which is defined in EPRI report TR-100844 [9], is performed to ensure that the characteristics or attributes of cables essential for operation are maintained. The best types of CM now available are:

- Visual/Tactile – Look and Touch
- Mechanical – Compressive Modulus (Indenter)
- Chemical – Oxidation Induction Time or Temperature (OIT or OITT)
- Chemical – Swell/Gel
- Chemical – Density

Early data from nuclear magnetic resonance (NMR) research indicate that this technique will also work well and requires as little as 0.1 milligram of material.

Visual/Tactile Inspection of Physical Condition

A periodic visual/tactile (touch) inspection is a very powerful technique for evaluating cable system component aging because the effects of many degradation mechanisms are readily detectable through sight and touch. The relative condition of the cables can usually be ascertained by simply performing a walkdown and observing changes in texture, color, size, and flexibility. For example, a cable that shows cracking, whitening, and/or brittleness is likely to have been exposed to heat. Similarly, a cable that has softened and discolored might have suffered damage caused by external chemicals. There are some cases, however, when a cable or component that exhibits no indications of degradation might still be degrading at a significant rate.

Figures 6-1 and 6-2 present visual examples of the effects of thermal aging on PVC[8] and ethylene propylene rubber (EPR) used for cable insulation and jackets. All of the specimens were subjected to the same aging temperature and were removed from the aging ovens at one-week intervals (shown left to right as aging time increased). Figure 6-3 shows similar aging steps on Hypalon-jacketed cables that were aged during development of training aids used for the assessment of cable aging [2].

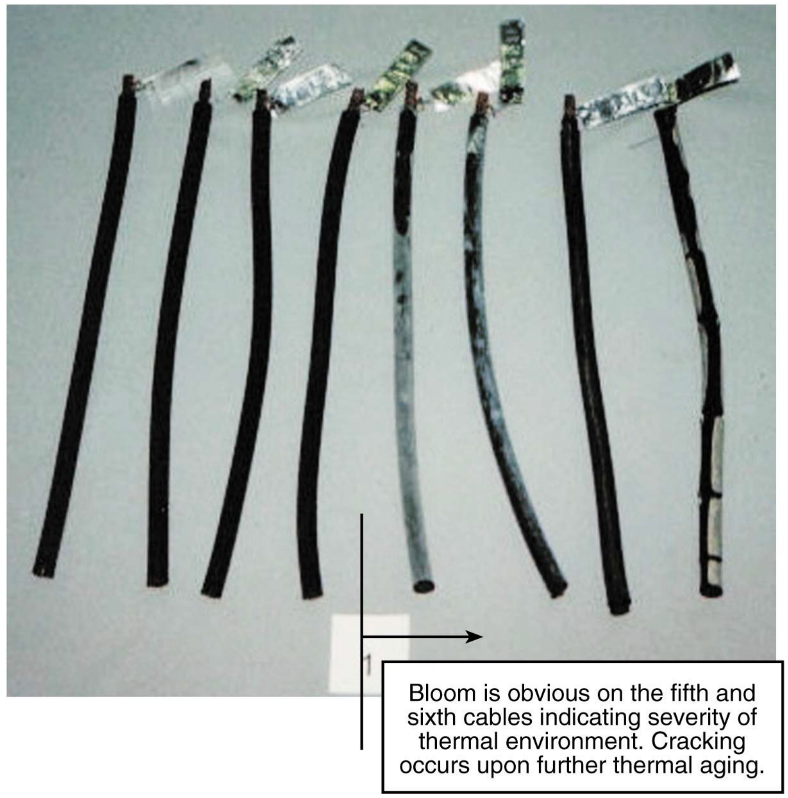

Figure 6-1
Progressive Aging of PVC Jackets on Small Cables

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[8] PVC has not been used as an insulation in field cables in the United States to any great extent. However, plants that received operating licenses prior to the mid-to-late 1970s might have a significant amount of cable with PVC jackets. Plants licensed later tend to have cables with neoprene and Hypalon, rather than PVC, jackets.

Figure 6-2
Progressive Aging of PVC Jacket and EPR Insulation When Exposed to the Same Environments

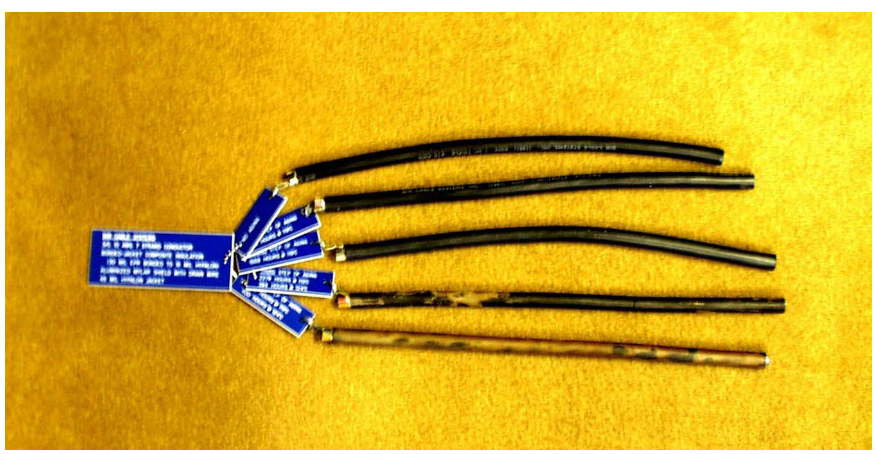

Figure 6-3
Aged Hypalon Jackets on Cables with Bonded Jacket EPR/Hypalon-Insulated Conductors

In Figure 6-3, aging increases from top to bottom. The bottom two cable samples were highly thermally aged. The upper three cables retain their original black surface color. The lower two cables show progressively more bloom from thermal stress. **Note:** Bonded jacket insulation of the single conductors of these Boston Insulated Wire Co. cables showed residual flexibility, even in the highly aged cable.

Maintenance personnel can easily inspect the visible portions of leads, terminations, and field cables while performing normal maintenance on attached equipment. Visual inspection can identify discolorations, crazing, and cracks that could be indicative of significant deterioration. Hot spots are often at the end device, which generally requires periodic maintenance. Accordingly, inspection of cable hot spot segments can be integrated into normal periodic maintenance activities.

Periodic inspection of cable segments at equipment terminations or routed near hot spots is justified because the majority of cable and termination aging is localized. Visual inspection of bulk runs of cable is limited as an aging management technique because bulk runs generally age slowly. Access is often restricted because much of the cable is routed in trays, conduits, or duct banks. Therefore, large expenditures of resources are not justified by the information that could be obtained from periodic inspection of these sections of cable. Detailed guidance and helpful examples for performing a walkdown have been prepared by utility representatives and are presented in Appendix A of EPRI report TR-109619 [1].

Visual/tactile techniques should be used as the initial assessment method when beginning cable system aging management to determine if significant aging has occurred. A visual/tactile assessment is relatively inexpensive to implement and can detect discoloration, hardening, cracking, and exuding plasticizers (PVC only). Each of these conditions can be indicative of severe aging of cable jackets and insulations. For example, significant hardening indicates that jackets and insulations have lost their tensile elongation properties and can crack if they are disturbed physically or exposed to a steam environment. This method is a relatively gross indicator of aging, but can be used for screening to identify aging in the areas with the most adverse environments and circuits, which are at the highest risk for age-related degradation.

Identification of aging is relatively easy for many insulation and jacket materials. Significant aging can usually be detected by light bending of the cable or by pressing a thumbnail into the cable surface. If the cable flexes easily or the jacket compresses under the pressure of the thumbnail, aging is not significant. If the cable is stiff and hard, significant aging has occurred. Although identifying significant aging is easy, discerning between degrees of significant aging is more difficult and subjective. Using visual/tactile assessment as the initial screening tool allows a utility to determine quickly and inexpensively if any significant aging has occurred. If the screening shows little or no significant aging, then sophisticated assessments of the cable system are not necessary and a new visual/tactile assessment can be scheduled for a later date. If a significant amount of aging is detected, then the use of more sophisticated condition monitoring techniques is desirable to determine the degree and scope of aging in the cable system.

Jackets can be used as a leading indicator of thermal degradation, regardless of the type of insulation that is covering the conductors. Jackets can be evaluated in trays and junction boxes along the cable run, but insulation can only be evaluated at terminations, provided it is not covered by heat-shrink tubing or tapes. Jackets of cables located in conduits can only be evaluated for physical attributes in junction and pull boxes.

An evaluator must be familiar with the cable's unaged condition, as well as the changes to visual and physical characteristics as the cable ages. Different polymers have different initial physical characteristics, and the construction of the complete cable can change its apparent physical characteristics (that is, its feel, but not its actual measurable physical parameters). When cable leads must be moved during maintenance of the connected equipment, a rough indication of the degree of hardening, if any, can be determined by touch. If an insulation or jacket that is normally pliable when not severely aged is found to be stiff or cracked, then the responsible engineer can evaluate the condition of the cable and initiate appropriate corrective actions.

A general material stiffness table is presented at the end of Appendix A. Also, an EPRI report, *Training Aids for Visual/Tactile Inspection of Electrical Cables for Detection of Aging* [2], describes training aids that have been developed to teach personnel how cables will age. The training aids contain individual insulated conductors and related cables in the unaged state, as well as in four steps of thermal aging. The aids illustrate construction of commonly used instrumentation and control cables and show how the insulations and jackets age.

The most commonly used materials for cable insulations and jackets are ethylene propylene rubber (EPR), chlorosulfonated polyethylene (CSPE), which is also known by its trade name Hypalon, neoprene (chloroprene), polyvinyl chloride (PVC), and cross-linked polyethylene (XLPE). The visual/tactile aging characteristics of these materials are as follows:

- EPR, CSPE (Hypalon), neoprene, and PVC harden as they age. When these materials are severely aged, they will crack when bent.
- EPR that is covered with CSPE also hardens as it ages; however, the two materials age at different rates (CSPE ages faster). Therefore, if the CSPE jacket is bonded to the underlying EPR insulation and is severely aged, then it will crack when bent and the crack can extend downward into (and through) the EPR. A detailed investigation of bonded CSPE jackets is presented in EPRI report 1001002 [10].
- XLPE is a relatively hard plastic, and detecting aging is more difficult because its physical properties are relatively stable throughout its life. XLPE insulations have no discernible differences in hardness or flexibility through most levels of expected aging. Thus, manipulation (bending) and

compressive modulus (Indenter) do not detect aging of XLPE. The jackets (generally neoprene or Hypalon, sometimes PVC) of XLPE cables can generally be used as leading indicators of aging; otherwise, sampling and lab testing must be used for XLPE.

Mechanical – Compressive Modulus (Indenter)

Significant mechanical property changes, such as elongation-at-break and density changes, occur due to thermally induced aging. These changes occur before changes to the electrical performance of the dielectric; that is, the mechanical properties must change to the point of embrittlement and cracking or beyond before significant electrical changes are observed.

Compressive modulus is a mechanical property of insulation and jacket materials, and it can be used to monitor the aging of any material that exhibits an orderly change in mechanical properties as it ages.[9] Rubber and rubber-like materials, such as EPR, silicone rubber, neoprene, PVC, and CSPE, can all be monitored in this manner. Compressive modulus does not work well for XLPE. However, if neoprene or CSPE jackets have been used on cables with XLPE insulation, then the jackets can be used as indirect aging indicators for the insulation.

The degree of aging can be established by comparing the compressive modulus measured on installed cables to the results from cables that are artificially aged to the thermal levels expected in service. The Indenter Polymer Aging Monitor (Cable Indenter) is a currently available test device that uses the compressive modulus concept. The system is self-contained and portable, and can be used for both in situ and laboratory evaluation. The system has been proven effective at evaluating and profiling cable damage resulting from localized heat sources. Evaluation of the Indenter is described in EPRI report TR-104075 [11].

Chemical – Oxygen Induction Time (OIT)

Oxidation induction time (OIT) is a means of evaluating aging by measuring the period of time before a small sample of insulation experiences rapid oxidation when subjected to a continuously elevated temperature in an oxygen environment. The test evaluates the amount of antioxidants remaining in an insulation material. When the antioxidants are depleted, the material properties will begin to degrade (in some cases relatively rapidly). OIT results for XLPE are fairly easy to evaluate; the results for some materials, such as highly filled EPR, are more difficult to interpret. OIT should only be used if the mechanical (compressive modulus) method does not provide useful data for a specific material. (It can also be used if additional confirmation of results is desired.)

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[9] The cable industry has also used destructive tensile strength and elongation tests on specimens taken from the field to characterize aging of cable materials and evaluate failures. These tests are most often used to analyze cables that have failed to determine the root cause of failure.

OIT tests require that a small sample (that is, 3 milligrams per test; the average of three or more tests is desirable) be removed from the insulation or jacket. Samples at terminations can be taken by removing terminal lugs, stripping a small segment of insulation (0.5 cm or less), and relugging the conductor. Surface specimens can be shaved from insulations, but controlling the depth of the cut is difficult and will generally require repair. Methods that can be used to remove specimens from different types of cables are described in EPRI report TR-112233 [12].

Chemical – Swell/Gel

Swell and gel tests are laboratory tests that can be used to assess aging by evaluating the degree to which polymers swell or dissolve when heated in solution. These are standard laboratory tests. The degree of swelling and residual gel is related to cross-linking of the polymers during aging. As cross-linking progresses with aging, the materials swell less or have more residual material. These tests require a reasonably large amount of material (200 mg). They are not difficult to perform, but are lengthy due to the length of time required for heating the material in solution.

Chemical – Density

The density of typical cable materials increases with aging. While the increase in density is only a small percentage, measurements can be made accurately with small samples (5–10 mg). Two methods are available. The first method uses a column of high-density solution that has a density gradient that increases from the top to the bottom of the column. The density is measured by determining the point at which the specimen reaches neutral buoyancy in the column. Different solutions are required to achieve different density ranges in a column. This method is used in the EPRI Natural Versus Artificial Aging Program and is described in EPRI reports NP-4997 [13] and TR-100245 [14]. The second method uses Archimedes' principle. The sample is weighed in air and then in alcohol. The density can be calculated from these two values, independent of volume.

Condition Monitoring Data

None of the condition monitoring techniques are useful without data that provide the trend of the monitored parameter with exposure to temperature. A resource that contains condition monitoring research data from a number of sources has been placed into a database for use by both researchers and utilities. The data are available in EPRI database 1001001 [15].

Section 7: Service Condition Assessment and Cable Aging Remediation

If data obtained using the condition monitoring methods described in the previous chapter indicate that relatively rapid aging is occurring in certain cables, then an evaluation should be made to determine if the service conditions causing the aging could be modified. The following sections describe actions that can be taken to assist in the evaluation.

Temperature Monitoring and Environmental Profiling

Temperature monitoring and environmental profiling are methods used to characterize the environment(s) in which cable systems operate. Environmental monitoring is useful for the assessment of cables found to be aging rapidly and determination of the expected rate of aging in areas that would be likely to have elevated temperature conditions.

Although the operating environments for most cables cannot be significantly altered cost- effectively to reduce thermal degradation,[10] a more complete understanding of environments can be useful in determining the lives of the cables. Knowledge of actual temperatures at or near the surface of cables that are aging prematurely can be used to determine the most appropriate action to take and when to take it. For these cables, use of actual temperatures can also be used with the Arrhenius model to more accurately predict the rate of aging and support the development of replacement schedules.

Temperature monitoring data can also be used to determine more accurate lives for cables located in areas that are expected to have more severe normal environments. Assumptions made regarding the service environment of cable system components can be overly conservative or not representative of actual thermal exposure. Estimates of cable life based on conservative thermal analyses can increase significantly if actual temperature exposure data are used. Further discussion and suggestions regarding this approach are provided in Sections 4.8 and 5.0 of EPRI report TR-104873 [16]. An example of the significant effect that this approach can have is illustrated in Section IV, Part One of EPRI report TR-106687 [5].

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[10] Some cables can be rerouted or shielded to minimize localized thermal effects; however, this solution is not applicable to the great majority of plant cable.

Analysis of Circuit Loading and Operating Time

An accurate determination of circuit loading is important to the evaluation of cable system life. Thermal degradation of installed cable can result from either environmental conditions (that is, those external to the cable) or ohmic heating from conductor current. Temperature rise caused by ohmic heating of the conductor must be considered in those instances where the effect on insulation or jacket aging is appreciable. For most low-voltage cables, ohmic heating is of little concern because 1) the cables operate well below their rated ampacities and, therefore, generate little heat, or 2) the cables operate intermittently, so that the fraction of their lifetime spent at an elevated temperature is small.

Only power cables connected to loads that are operated for substantial fractions of the installed cable life need to be considered in a circuit-loading analysis. Those loads that are operated continuously or near-continuously can be readily identified through assessment of plant operations, examination of plant operating or run-time logs, and discussions with plant personnel responsible for the operation of the equipment. In addition to individual circuits, load center and transformer feeder[11] cables should be evaluated for ohmic heating effects. These applications are unusual in that their loading is continuous and they can operate at 80% of their rated ampacity. The cable temperature rise resulting from the loads can be calculated using the industry standard formula given on page III of IPCEA P-46-426 [17], and used to evaluate the effect on thermal aging of individual cable materials using an Arrhenius analysis. An analysis that was made using this method is presented in Section 5.2.3.2 of EPRI report TR-107527 [18].

Infrared Thermography

Infrared thermography is a nondestructive maintenance and surveillance technique used to detect and evaluate component heating. Thermography is not a condition monitoring technique itself; rather, it can be used to identify and describe the thermal aging influences on cable systems.

All materials radiate infrared energy—the hotter the component, the more energy that is radiated. Infrared detectors can sense infrared radiant energy and produce signals proportional to the temperature of the targeted component.

Because of the large amount of cable in a plant, spot-measuring devices are of limited use in monitoring bulk cable runs. However, abnormally hot electrical connections could be indicative of problems in the conductor coupling. For example, an excessively hot splice might indicate a high-resistance connection. The overheating could degrade the surrounding organic materials and cause eventual electrical failure. Identifying such high-temperature components could

[11] Certain large transformers, such as the auxiliary or startup transformers, might have multiple conductors per phase. These circuits can have high enough loading that transpositions of the conductors within the phases are required to balance magnetic loadings within the phases. If the transpositions were not implemented, some conductors would have very high currents and some would have very low currents, due to the magnetic fields. If this occurred, the ohmic heating on the high-current conductors would lead to early aging.

allow correction of the condition before significant degradation occurred (see the discussion for Information Notice 83-37 in Appendix A of this report). The best locations to perform thermography studies are those described in the first few sections of Chapter 5.

Cleaning

Cleaning of cable and termination components is usually not required and is only done as part of other maintenance or testing of connected components. It could also be done in response to anomalous behavior or failure of the cable. Surface dirt and contaminants have no significant effect on the life of most cables; however, in certain cases, the presence of dirt or contaminants can reduce the life or functional properties of connected components (such as terminal blocks) that are exposed to moisture and voltage stress. Cleaning of the termination system can be useful in eliminating surface tracking paths and precluding electrical failure.

Repair or Replacement

Repair or replacement of cables is performed almost exclusively in response to deficiencies or degradation identified by plant personnel during operations, maintenance, or testing. Repair of cables is performed when the aging or degradation of a cable is confined to a limited area, and is usually limited to retermination. For example, a cable end that has been heat-damaged by exposure to a process device can be cut back a short distance from the end device and reterminated if sufficient slack is available. Alternatively, a junction box can be installed at a convenient location and a new section of cable installed to replace the damaged section.

In general, preventive replacement of cables is unnecessary except in instances where the continued longevity of the cable is in question, and failure of the cable might have a significant impact on plant operations or safety. For many applications, replacement of the cable can only be practical during maintenance or refueling outages due to the effect on operations.

Appendix A: Previously Identified Causes of Cable Aging Problems

Table of Identified Condition Issues

Table A-1 describes 17 causes of known cable aging problems and contains immediate and long- term recommended actions. Additional explanatory information follows the table.

Table A-1
Known Causes of Cable Aging and Recommended Remedial Actions

Cable Condition	Cause	Immediate Action	Long-Term Action
Blisters in jacket surface	Severe external heat from a local source	Identify heat source and either remove it or install a shield between cable and source. Evaluate severity of damage; if underlying insulation is damaged, replace cable.	If cable has not been replaced, inspect at next outage to monitor for any change.
Brittle	Excess heat (current load or external source)	Identify heat source. If it is ohmic heating, review circuit loads. If the source is external, either remove it or install a shield between cable and source. Evaluate effect on safety/operability. Replace cable if insulation is cracked or very brittle. If some flexibility remains, continue use.	Inspect at next outage to monitor for any change.
Bubbles in jacket surface	Moisture under jacket (manufacturing defect)	Replace cable at next outage to eliminate manufacturing defect if insulation is similarly and severely affected.	None.
Burned	Excess heat from either current load or external source (hot spot)	Identify heat source and extent of damage. If burn extends for considerable length, then current load is excessive; replace cable with larger size. If burn area is localized, then eliminate hot spot or install shield between it and cable. If burn is at or near a crimped connection, determine if lug was properly installed (verify crimping method and force).	Inspect at next outage to assess rate of change.

Table A-1 (continued)
Known Causes of Cable Aging and Recommended Remedial Actions

Cable Condition	Cause	Immediate Action	Long-Term Action
Cracked	1. Severe aging 2. Mechanical damage 3. Ultraviolet radiation from fluorescent lights	Determine if crack is only in jacket or if it extends into insulation. If crack is only in jacket, then apply temporary repair (tape/heat shrink) to jacket. If crack is in insulation, then replace cable. Identify source of damage.	Inspect at next outage for any change. Replace cable if cracking has extended beyond original area.
Discolored	1. Initial aging 2. Chemical spill	1. None if not accompanied by brittleness or cracking. 2. Review data for interaction between material and chemical. Clean cable or replace.	Inspect at next outage for any change.
Dull	1. Normal – new 2. Chemical spill	1. None. 2. Review data for interaction between material and chemical. Clean cable or replace.	Inspect at next outage to look for any change.
Green Ooze	Plasticizer from PVC	Clean contacts where wire was attached. If the ooze was produced from PVC insulation, then remove wire and install new wire. If the ooze was produced only from a PVC jacket, then no cable replacement is required.	None.

Table A-1 (continued)
Known Causes of Cable Aging and Recommended Remedial Actions

Cable Condition	Cause	Immediate Action	Long-Term Action
Limp	1. Aging process for certain materials 2. Chemical spill	1. None if integrity remains. If softening is severe, replace. 2. Review data for interaction between material and chemical. Replace if necessary.	Inspect at next outage to look for any change.
Oily	1. Manufacturing defect 2. Oil/chemical spill	1. No action required. 2. Identify oil or chemical and review data for interaction with material. Clean cable or replace if cable material is susceptible to oil or chemical contamination.	None.
Red goo at splice	Adhesive from heat-shrink material flowed out of splice.	No action required. This is a normal condition in most cases.	Inspect at next outage to look for any change.
Shiny	1. Normal – new 2. Chemical spill	1. None. 2. Identify chemical and review data for interaction with material. Clean or replace cable.	Inspect at next outage to look for any change.
Slimy	Wetting and biological growth	Identify source of moisture and eliminate it. Clean cable.	Inspect at next outage to look for recurrence.

Table A-1 (continued)
Known Causes of Cable Aging and Recommended Remedial Actions

Cable Condition	Cause	Immediate Action	Long-Term Action
Sticky or tacky	1. External – chemical or oil spill	1. Identify source and review data for interaction with insulation material. Clean cable or replace if material is susceptible to the chemical.	1. None.
	2. Internal – plasticizer from PVC (might or might not be green)	2. Evaluate extent of conductor corrosion and replace cable if needed.	2. Inspect at next outage to look for change.
Stiff	1. Normal – new	1. None. See Table A-2, General Indications of Material Stiffness	1. None.
	2. Intermediate aging process for some materials	2. A previously flexible material will have exceeded 50% of its life at this point.	2. Inspect at next outage for any change.
Swollen	1. Moisture absorption	1. Identify source and stop. Evaluate if insulation has been affected significantly; if so, replace cable.	Inspect at next outage to look for recurrence.
	2. Chemical spill	2. Review data for interaction with insulation material. Clean cable or replace if material is susceptible to chemical contamination.	
White dust	Bloom from PVC jacket	The appearance of bloom can indicate that PVC has aged over 50% of its thermal life. Evaluate aging using Indenter or stiffness relative to new PVC.	Inspect at next outage to look for any change.

Abbreviations and Definitions

Bloom – visible layer of chemical residue on the surface of the cable. The material has exuded (oozed) from the body of the cable polymer (most often the jacket). The cable surface becomes covered with a powdery crust. For rubbers, the layer is generally excess curing sulfur. For PVC, the material is plasticizer or HCl.

Chloroprene – neoprene

CM – condition monitoring

CSPE – chlorosulfonated ethylene propylene rubber (Hypalon)

EatB, EAB – elongation at break, a polymer CM test

EPR – ethylene propylene rubber

FTIR – Fourier transform infrared spectroscopy, a CM test

Hypalon™ – chlorosulfonated ethylene propylene rubber

HCl – hydrochloride ions

IR – insulation resistance, a troubleshooting test

OIT – oxygen induction time, a CM test

OITT, OITemp – oxidation induction temperature, a CM test

PF – power factor, a troubleshooting test

PI – polarization index, a troubleshooting test based on IR

Plasticizers – high-boiling organic liquids or low-melting solids that are added to hard or tough resins—chiefly PVC—to make them more flexible. Epoxy plasticizers, derived from vegetable oils (such as soybean and linseed), give heat and light stability to PVC compounds (according to the *Modern Plastics Encyclopedia* [19]).

PVC – polyvinyl chloride

TDR – time domain reflectometry, a troubleshooting test

XLPE – the abbreviation for cross-linked polyethylene

Issues, Concepts, and Operating Experience

Chemicals (Effects of)

Interactions between chemicals and the various materials typically used in cable construction can be determined from a variety of published sources. Two good sources are as follows:

- Engineering handbook published by Parker Seal [20]. Also see updated data at http://www.parker.com/sg/parkerseals/css_catalogs.asp.
- Handbook of Plastics and Elastomers [21]

Operating Experience

The nuclear industry has an operating experience process whereby events are captured and shared within the industry. This formal process lends itself to identifying issues, trends, and lessons learned. Below is a listing of some of these operating experience events, with cross-references provided for examples that are featured in Information Notices summarized later in this appendix.

Connections: Related Operating Experience

A set screw in the barrel of a cable lug was over-tightened during installation, thereby causing some stranded wire to break, which resulted in a high-resistance joint. Long-term localized heating in the terminal lug degraded the connection. (See “IN 83-37” in this appendix.)

External Heat Sources: Related Operating Experience

A failed cable showed evidence of insulation degradation and arcing between two phases to the sheath of the cable caused by temperature-induced accelerated aging and degradation of the insulation. The source of the heat was a bare high-temperature feedwater line and pipe flange whose thermal insulation had been removed during repair work and had not been replaced. (See “IN 86-49” in this appendix.)

Burn damage to internal wiring in Limitorque motor operators was caused by electric heater elements installed in the limit switch compartment. The wiring was burned as the result of its close proximity to, or contact with, the heater element or bracket. The wiring was not properly routed and was not restrained from contacting the heat or bracket. (See “IN 86-71” in this appendix.)

Motor lead wires insulated with Nomex-Kapton are susceptible to insulation degradation when operated in normal non-harsh conditions. (See IN 87-08, available online at http://www.nrc.gov/reading-rm/doc-collections/gen-comm/info-notices/1987/in87008.html.)

Fluids Inside Cable: Related Operating Experience

Green Ooze: A vegetable oil plasticizer in PVC insulation, which decomposes at high temperatures, oxidizes, and then interacts with the copper conductor. This green substance can be a conductor in liquid form but, when dried, can be either a conductor or an insulator depending on the amounts of copper oxide salts that are present. A black or green sticky gel underneath the insulation can result from the interaction of corrosion on the surface of the copper conductor and the chlorine leaching from the PVC. (See "IN 91-20" and "IN 94-78" in this appendix.)

Oily fluid seeping from cut ends of Okonite power and control cables was caused by the application of excess lubricant to the surface of filler materials covering the conductors of multiconductor cables. (See "IN 84-01" in this appendix.)

Fluorescent Lights (UV): Related Operating Experience

Several dozen wires made with high-density polyethylene (HDPE) and installed in the control room of the D.C. Cook nuclear plant were discovered to have circumferential cracks. The wires with white insulation contained the cracks, and the copper conductor could be seen. Identical wires that had blue and black insulation did not have any cracks. There was no apparent heat source to age the white-insulated wires. A review of technical literature determined that a special type of aging might have been occurring, namely, degradation of polyethylene caused by the ultraviolet (UV) radiation emitted by fluorescent lights. The white-colored insulation did not contain an anti-radiation additive. (Carbon black inhibits the degrading effects of UV.) UV will also cause PVCs to crack if they do not have anti-radiation additives.

Information Notices

IN 83-37: Transformer Failure Resulting from Degraded Internal Connection Cables

An emergency bus overheated, causing the feeder breaker to trip on overcurrent. The transformer was damaged beyond repair by apparent arcing at its transformer winding taps. The failure was attributed to improper assembly of transformer winding tap cables and long-term, undiagnosed, heat-induced degradation. The set screw, which attaches the cable to the barrel of the lug, was over-tightened during installation, which caused some of the aluminum stranded wire to break, thereby creating a high-resistance joint. Arcing is thought to have started in the barrel of the lug as a result of the resistance joint. Long-term localized heating in the terminal lug over a period of time weakened and degraded the connection.

IN 84-01: Excess Lubricant in Electric Cable Sheaths

Excess lubricant might have become trapped inside cable sheaths during manufacture and can drip out where cable sheaths have been cut for terminations. An oily fluid was observed seeping from cut ends of some power and control cables supplied by the Okonite Company. It is the practice of the Okonite Company to apply an extruded filler material over the conductors of multiconductor cable to provide a uniform cylindrical surface on which to apply the outer cable jacket. Before the jacket is applied, the exterior surface of the filler material is treated with an oily lubricant to facilitate the jacket application. Prior to early 1979, the filler material layer was so thin that sometimes the material tore in handling operations before the lubrication step. When this occurred, excess lubricant entered the cable bundle and remained there. Okonite reports that in early 1979 the situation was identified and corrected by slightly increasing the thickness of the filler layer and changing the formulation of the filler material.

In another case, single conductor power cables were identified where water ran out between the strands of the conductor. The water was condensate from steam used in the insulation vulcanizing process.

IN 86-49: Age and Environment-Induced Electrical Cable Failures

Inspection of the failed cable showed evidence of insulation degradation and arcing between two phases to the sheath of the cable. The most likely cause was temperature-induced accelerated aging and degradation of the cable insulation. The source of this heat was a bare high- temperature (400°F/204°C) feedwater line and pipe flange in the immediate vicinity of the cable. The thermal insulation had been removed from the pipe during the previous repair of a gasket leak and had not been replaced.

IN 86-71: Recently Identified Problems with Limitorque Motor Operators

Burn damage to internal wiring in Limitorque motor operators was caused by electric heater elements installed in the limit switch compartment for storage purposes. The internal wiring is located in the operator limit switch compartment and is being burned as a result of its close proximity to, or contact with, the installed limit switch compartment electric heater element or heater bracket. The wiring is not properly routed and is not restrained from contacting the heater or heater bracket. Although the heater is intended for use only during storage, its use has been shown to cause serious degradation of internal wiring.

IN 87-52: Insulation Breakdown of Silicone Rubber-Insulated Single Conductor Cables During High Potential Testing

Failures of silicone rubber-insulated cables occurred during high potential testing. Significant decreases in insulation wall thickness could result from lower-than-expected impact forces. The licensee speculates that such impact forces, which could affect the dielectric withstand characteristics of the cable, can occur during: 1) handling by the manufacturer, 2) shipping, 3) receipt and storage, or 4) the installation process.

IN 89-63: Possible Submergence of Electrical Circuits Located Above the Flood Level Because of Water Intrusion and Lack of Drainage

Electrical circuits that are located above the plant flood level within electrical enclosures might become submerged in water because appropriate drainage has not been provided.

Failure of electrical circuits during service conditions can occur due to submergence if water enters these enclosures and there is no provision for drainage. The electrical enclosures addressed by this notice include terminal boxes, junction boxes, pull boxes, conduits, condulets, and other enclosures for end-use equipment (such as limit switches, motor operators, and electrical penetrations), the contents of which can include cables, terminal blocks, electrical splices, and connectors.

IN 91-20: Electrical Wire Insulation Degradation-Caused Failure in a Safety-Related Motor Control Center (MCC)

The licensee identified a clear, hardened coating on one of the contactors in one of the compartments in the MCC. The licensee identified a green "liquescent" substance coming out of the wires that connect the associated MCC electrical breaker to its forward and reverse contactors and hardening on the contactors. A laboratory analysis identified the green liquescent substance as a "vegetable oil plasticizer," which is present in the composition of the cable's PVC insulation. The analysis indicated that the green liquescent substance is a conductor in liquid form, but when dried might either be a conductor or an insulator, depending on the amounts of copper oxide salts present. In addition, the color of the substance can vary depending on the amount of copper oxide salts present.

In another case, a licensee found a green substance seeping from the wires attached to the primary side of a control transformer, and a black and green sticky gel present on the entire length of the wire inside the wire's insulation. It was identified as an interaction between the corrosion products formed on the surface of the copper wire and the chlorine leaching from the wire's PVC insulation. The licensee stated that the sticky consistency of the material was a result of a slight depolymerization of the inner surface of the insulation and that moisture from the environment had been transported, by capillary action, into the wire strand bundles. The licensee suspected that an electro-chemical reaction contributed to the insulation degradation, which might have been accelerated by the high voltage differential across the control transformer.

IN 92-01: Cable Damage Caused by Inadequate Cable Installation Procedures and Controls

Inadequate cable installation procedures can cause cables to fail. Damage was attributed to the pulling stresses exerted during initial installation of the cables. Some of the cables had insulation removed down to the conductors. Pull cords were used to pull more cables through the conduits over the top of existing cables. This practice, called "pull-by," can cause damage to the existing cables from the sawing action of the pull cords and the friction of cables as they are pulled over existing cables. Such cable damage can be caused by the pulling stresses exerted during cable installation. If moisture enters the affected conduits, it can cause cables to short.

IN 94-78: Electrical Component Failure Due to the Degradation of Polyvinyl Chloride Wire Insulation

An ABB/Westinghouse relay failed because a green substance from the internal wiring, identified as polyvinyl chloride (PVC), had coated the instantaneous trip unit, thereby insulating the contacts and preventing the relay from operating (even at twice the normal trip current). The licensee did a laboratory analysis and identified the green substance as a copper chelate of the polyester plasticizer from the PVC insulation on the internal wire of the relay. Overheating of the wiring could have caused the release of the plasticizer. ABB analyzed the substance and concluded that the green substance was produced when a plasticizer released from the PVC insulation, which had decomposed at high temperatures, oxidized and interacted with the copper.

IN 2002-04: Wire Degradation at Breaker Cubicle Door Hinges

Circuit breaker cubicle wires connect electrical equipment mounted on cubicle doors to equipment inside the breaker cubicles. These wires flexed with each cycle of the door opening and closing. Over time, the wires degraded due to cold working and aging. A number of wire strands had been broken for some period of time based on the presence of corrosion at the end of the broken strands.

The wires connecting the door-mounted equipment with terminals inside the cubicle are supported by two vertical wire braces (also called wire looms), whose purpose is to prevent the wires from becoming pinched in the door hinge when the breaker is opened and closed. The types of wire damage included the following: completely broken wire, exposed and broken strands, damaged insulation, damage to the outer cloth jacket of the insulation, and damaged outer insulation, although the inner insulation was still intact. An evaluation indicated that cold working and aging of the wires were the causes.

Cold working: In certain cases the wires are forced into the side of the breaker cubicle when the cubicle door is closed. This can force the wire on the inside of the bend to exceed the minimum bend radius for a dynamic bend, resulting in cold working of the strands. Subsequent cycling of the door will eventually result in wire failure.

Age-related degradation of the wires: Over time, the plasticizer leaches out of the PVC insulation, resulting in embrittlement. Flexing of the wire causes the insulation to break. The loss of the mechanical support provided by the insulation focuses the bending at the break, speeding the cold working of the wire strands and causing eventual failure.

Stiffness

Some cable materials are relatively stiff when they are new, and other materials can be flexible when new but become stiff as they age. A general indication of material stiffness is shown in the following chart—the lower the elongation number, the stiffer the material.

Information on general indications of material stiffness can be found in Table A-2.

Table A-2
General Indications of Material Stiffness

Insulation or Jacket Material	Before Aging: Elongation at Rupture (Minimum %)	After Aging: Elongation at Rupture (Minimum % of Unaged)	Typical Aging Test (ICEA Standard or Manufacturer Specification)
Polyimide (Kapton®)	70-85	N/A	N/A
Polyvinyl Chloride (PVC) 60°C	100	65	100°C for 168 hrs
Ethylene Tetrafluoroethylene (ETFE) (Tefzel®), cross-linked	125	N/A	N/A
Polyvinyl Chloride (PVC) 75°C	150	75	121°C for 168 hrs
Chlorinated Polyethylene (CPE)	150	50	121°C for 168 hrs
Ethylene Propylene Rubber (EPR) – Type II	150	75	121°C for 168 hrs
Natural or Synthetic Rubber Ozone-Resisting	250	200 (absolute)	70°C for 168 hrs
Silicone Rubber Ozone-Resisting	250	125 (absolute)	200°C for 168 hrs
Cross-Linked Polyethylene (XLPE)	250	75	121°C for 168 hrs
Ethylene Propylene Rubber (EPR) – Type I	250	75	121°C for 168 hrs
Neoprene, jacket, general purpose	250	50	100°C for 168 hrs
ETFE (Tefzel®) – basic)	275		
Synthetic Rubber (60°C)	300	65	70°C for 96 hrs

Table A-2 (continued)
General Indications of Material Stiffness

Insulation or Jacket Material	Before Aging: Elongation at Rupture (Minimum %)	After Aging: Elongation at Rupture (Minimum % of Unaged)	Typical Aging Test (ICEA Standard or Manufacturer Specification)
Synthetic Rubber (75°C)	300	50	80°C for 168 hrs
Synthetic Rubber (90°C)	300	60	121°C for 168 hrs
Chlorosulfonated Polyethylene (CSPE)	300	50	121°C for 168 hrs
High-Density Polyethylene (HDPE)	300	75	100°C for 48 hrs
Neoprene, jacket, heavy-duty, black	300	50	100°C for 168 hrs
Fluorinated Ethylene Propylene (FEP), Teflon® (TEF)	325	N/A	N/A
Butyl Rubber Ozone-Resisting	350	60	100°C for 168 hrs
Polyethylene (PE)	350	75	100°C for 48 hrs
Natural Rubber (60°C)	400	85	70°C for 96 hrs
Natural Rubber (75°C)	400	75	80°C for 168 hrs

Also see the EPRI report *Training Aids for Visual/Tactile Inspection of Electrical Cables for Detection of Aging* [2], which describes training aids that have been developed to teach personnel how cables will age. The training aids contain individual insulated conductors and related cables in the unaged state, as well as through four steps of thermal aging. The aids illustrate construction of commonly used I&C cables and show how the insulations and jackets age.

Appendix B: Photographs of Common Causes of Aging

This appendix presents photographs of installed cables that are being subjected to conditions that could result in accelerated aging or wear-out of the cables before their intended design life. These photographs can be used as a training aid for personnel who are about to perform a walkdown of plant cables.

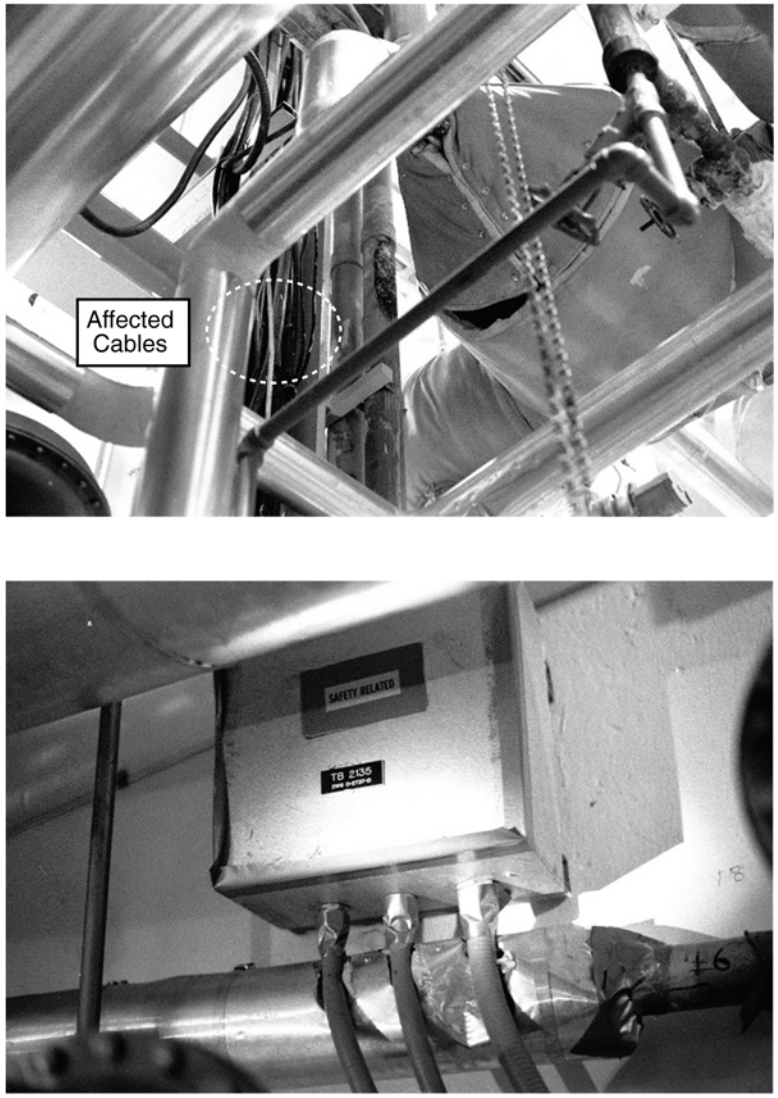


Figure B-1
Displaced Thermal Insulation on Valve Operator

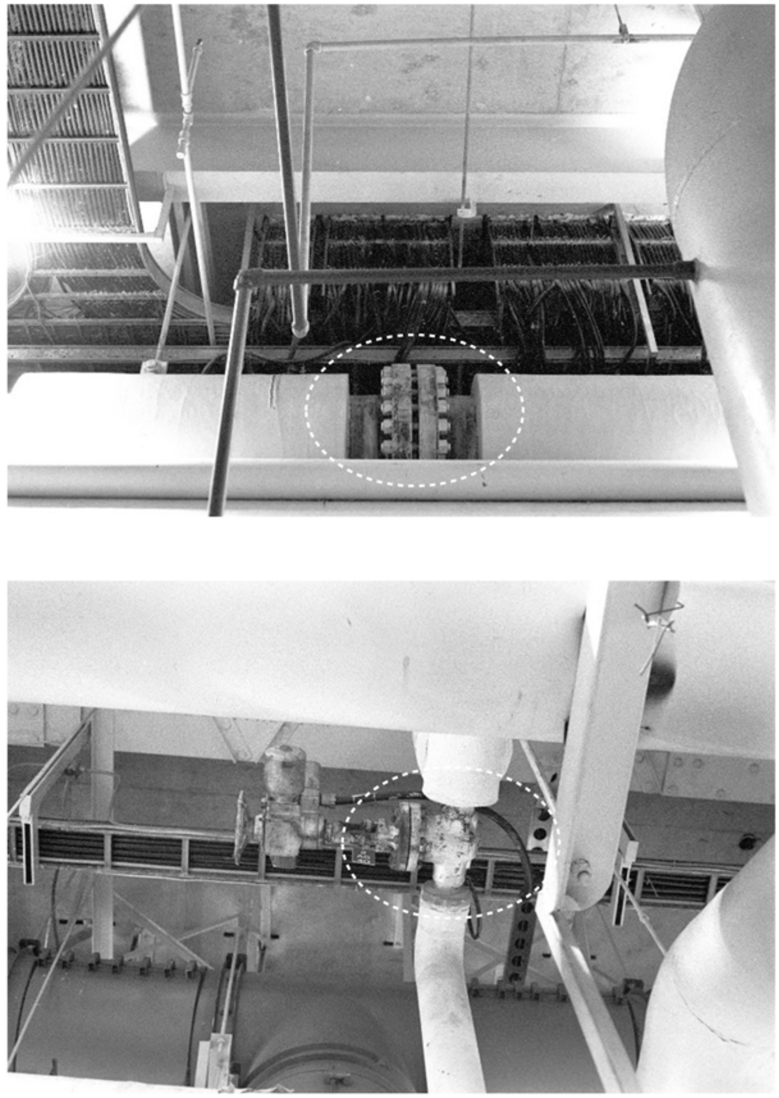


Figure B-2
Missing Thermal Insulation

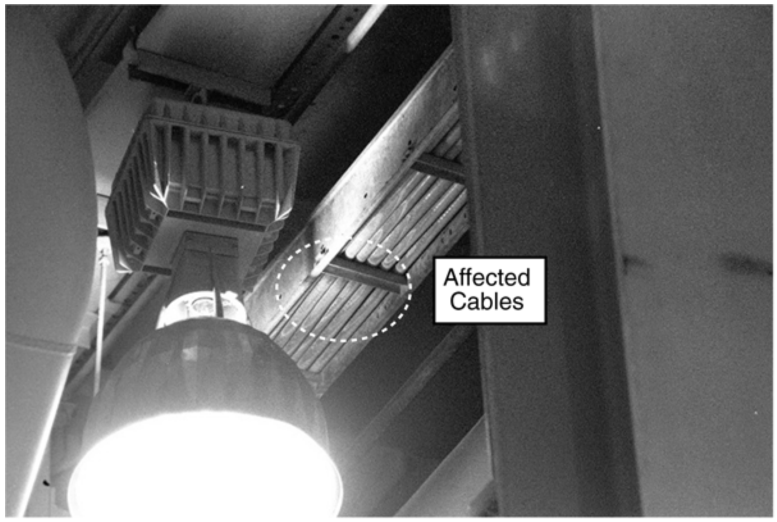


Figure B-3
Heat from High-Intensity Lamps

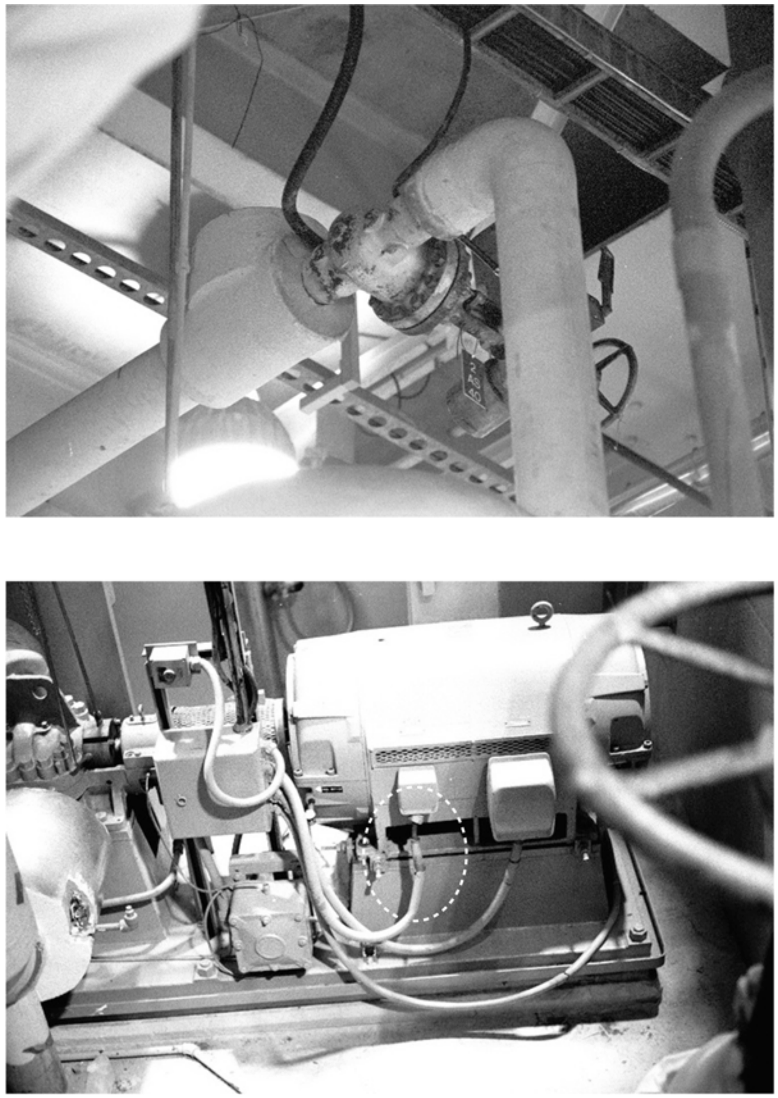


Figure B-4
Localized Hot Spot from Uninsulated Valve Affecting MOV Motor and Cable (top); High-Temperature Motor Affecting Cable (bottom)

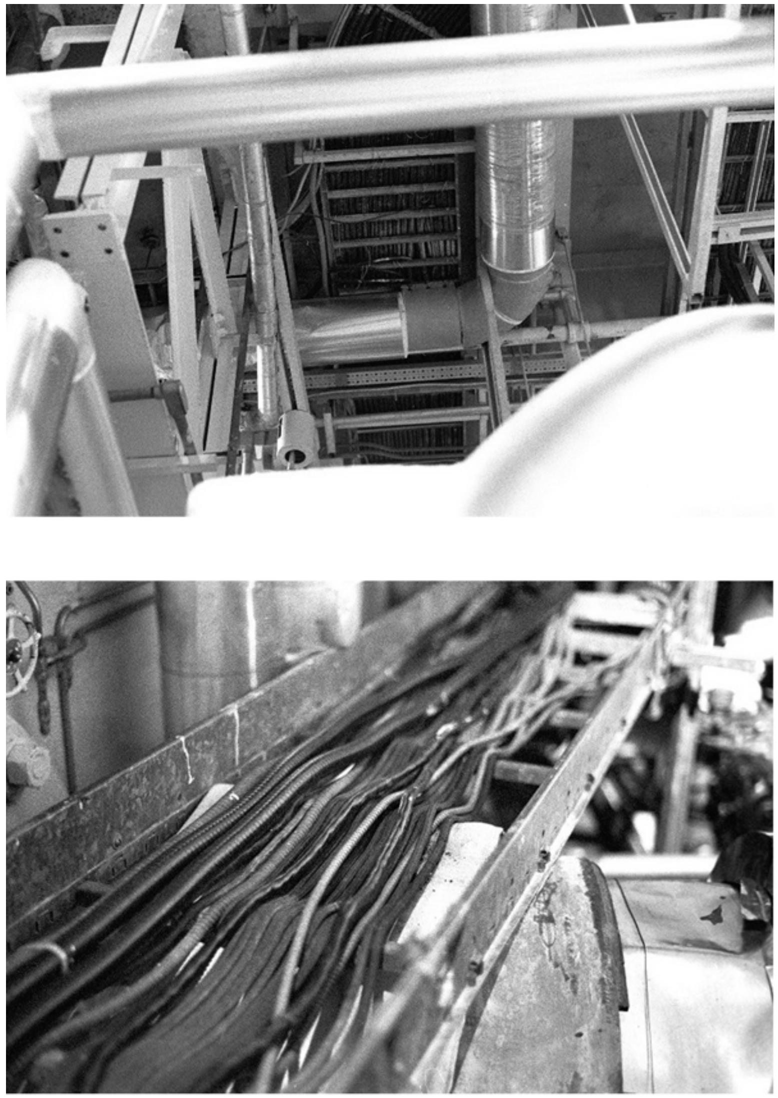


Figure B-5
Tray Above Hot Pipes

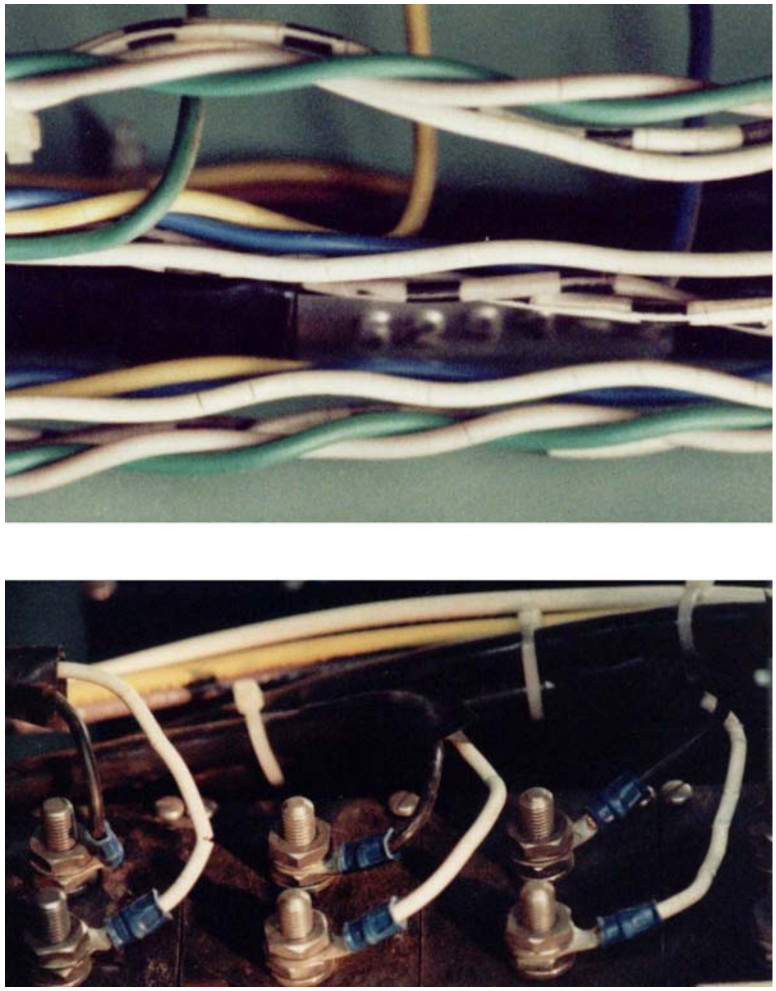
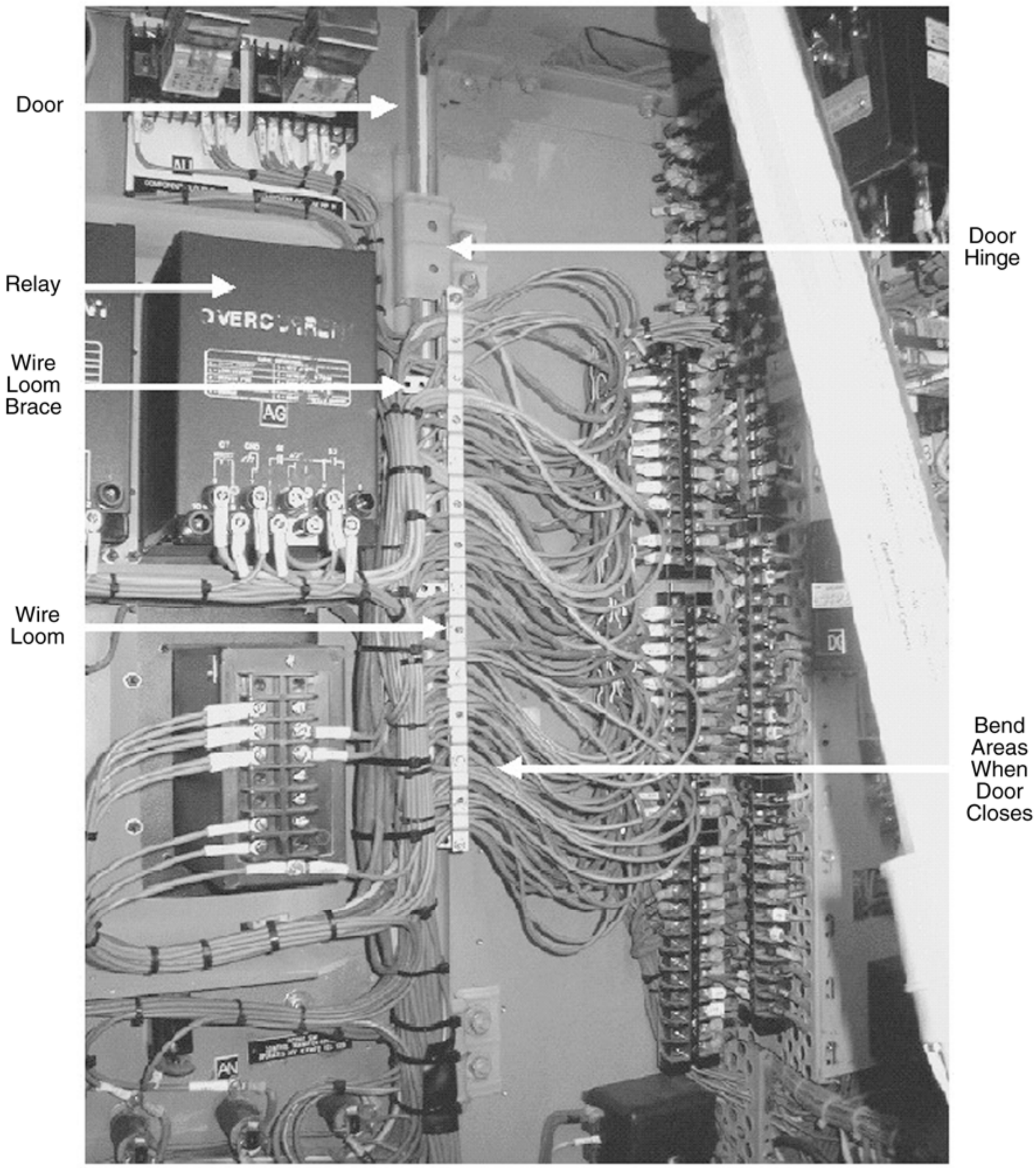


Figure B-6
Cracking of White Polyethylene (PE) Caused by Fluorescent Lights



Breaker Cubicle Interior

Figure B-7
Mechanical Damage to Conductor at Cabinet Door Hinge

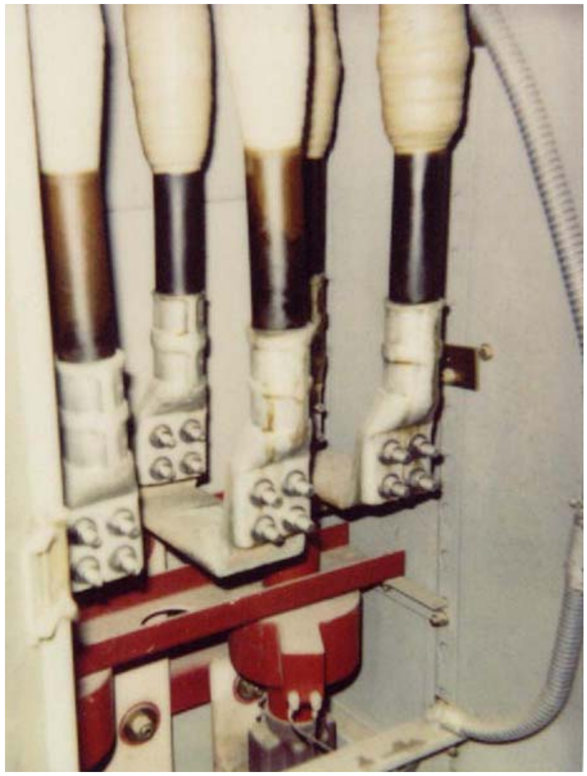


Figure B-8
Overheating Caused by Crimped Connection

The measured temperature at the discolored crimped connections was 60°F (33°C) hotter than at the other connections.

Appendix C: Understanding the Design of Low-Voltage Plant Cable Systems

Instrumentation Cables

The two basic types of instrumentation cable designs used in fossil plants are twisted shielded pairs, triplets, and so on, and coaxial types. While other specialty designs exist, they are beyond the scope of this document.

Twisted Shielded Designs

Instrumentation signals can be adversely affected by electromagnetic noise that exists in a power plant. To limit the noise in instrument circuits, the cables are constructed with shields that drain induced electrical impulses to ground. In twisted shielded designs, a shield surrounds a group of cabled (twisted) insulated conductors. The group may consist of two, three, or four conductors, depending on the connected instrument.

A number of different shield designs have been used. One of the more common designs uses aluminized polyester (often Mylar[12]) tape that is wrapped around a twisted pair or triplet of insulated conductors. A drain wire is placed along the aluminized side of the tape to provide a connection between the tape and the ground and to provide a convenient means of connecting the ground. Alternate means of shielding use a metallic shield, which can be in the form of a helically wrapped tape, a braid woven from fine wires, or fine parallel wires surrounding the pairs or triplets.

The insulations used in instrument and control cables are the same as those used in control and low-voltage power cables. These are cross-linked polyethylene (XLPE), fire-retardant ethylene propylene rubber (FR-EPR), bonded jacket EPR (chlorosulfonated polyethylene/EPR [CSPE/EPR]) and neoprene/EPR [NEO/EPR]), and silicone rubber. Polyvinyl chloride (PVC), although rarely used as an insulation in the United States, is commonly used as an insulation elsewhere in the world. In bonded jacket EPR, the EPR layer is not fire retardant. A NEO or CSPE jacket is bonded to the insulation layer to provide

[12] Mylar is a registered trademark of DuPont

fire retardancy. Less common, but occasionally found, insulations are butyl rubber, CSPE (Hypalon[13]), Kapton[13] (polyimide tape), and Tefzel[13] jackets are typically NEO, CSPE, or PVC (limited U.S. usage). Instrument cables are often rated for 300 V or less and are not subject to significant operating currents. Therefore, the insulation thicknesses on twisted shielded cables may be two-thirds of that used on control and power cable with similar conductor sizes, causing the insulation system to be more sensitive to thermal aging than control and power cables using the same insulation. Inside the power plant, thermal aging is the key aging concern. Most of the polymers will harden, eventually lose tensile properties, and then finally powder and fail if the aging is not controlled.

In instrument cable applications with underground segments where submergence occurs, jacket integrity is important. If jacket integrity is lost, additional grounds can occur on the shield, resulting in multiple shield grounds that will cause high circuit noise. Insulation stability is another potential submergence issue, but has not been reported as a cause of failures.

Coaxial and Triaxial Designs

In coaxial designs, a central conductor is covered by insulation, and the second conductor, a shield, is applied as fine wires or a wire braid over the insulation. A jacket is then applied over the shield. The shield is grounded at one end to reduce electrical noise. In triaxial designs, a second layer of insulation is placed over the shield, a second shield is placed over that insulation, and a jacket is applied. The outer shield is grounded, and the signal is carried by the inner shield and conductor from the sensor. The inner shield is connected to chassis common.

The two shields provide additional electrical noise reduction. Coaxial and triaxial cables are used on circuits having very small signals and on high-frequency circuits where noise reduction and specific impedances are necessary. The shields are grounded at a specific location depending on the circuit design. Multiple grounds will increase noise rather than reduce it. Therefore, for coaxial and triaxial cables, the jackets must remain insulators to prevent additional ground paths to the shields.

The polymers used as insulation in coaxial and triaxial designs are designed to have specific impedance characteristics. They are not designed for high-temperature conditions and have lower temperature ratings than power and control cables. Various insulations have been used including polyethylene (PE), XLPE, and EPR.

Mineral-insulated cables are available with stainless steel jackets. These cables are impervious to elevated temperatures. However, the connectors generally contain polymeric seals or seal systems that can age from elevated temperature.

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[13] Hypalon, Kapton, and Tefzel are registered trademarks of DuPont

Control Cables

Control cables have simple designs in which an insulated conductor is cabled with one or more additional cables. Cording (nonhydroscopic filaments) is applied to help make the assembly round, and then a jacket is applied. In some designs, an additional rubber layer is added over the cable's individual insulated wires to round the assembly before jacketing, and in other designs, additional jacketing material makes the cable round. The insulation thickness in most control cables is 30 mils (0.76 mm) thick. If non-FR-EPR insulation is used, an additional 0.015 in. (0.38 mm) of flame-retardant NEO or CSPE (Hypalon) is applied to add flame retardancy. Common insulations used in control cables are XLPE, FR-EPR, EPR with a bonded layer of NEO or CSPE, EPR with a nonbonded layer of NEO or CSPE, CSPE alone, silicone rubber, PVC, and butyl rubber. PVC is not used as insulation in the United States, but has been used in Canada, Japan, Korea, Eastern Europe, and the former Soviet Union. Butyl insulation was used in very few early plants. The most common insulations are XLPE, FR-EPR, EPR/NEO, and EPR/CSPE. EPR/NEO was phased out of manufacture by the early 1980s.

Although the insulation systems for most control cables are rated at 90°C at the conductor, the overall cables are not suitable for 90°C environments on a continuous basis. The jackets are rated at 75°C or less. In EPR with bonded CSPE, the CSPE layer ages faster than the EPR layer and becomes the controlling layer with respect to failure under manipulation of the cable during maintenance and under high-pressure steam accident environments such as those in containment.

A leading cause of control cable degradation is thermal damage. For control cables, ohmic heating is not a concern. Exposures to elevated temperatures from adjacent high temperature valves and piping or hot lighting fixtures are the concern. Damaged or missing thermal insulation on pipes and valves can cause significant damage to cable polymers in a relatively short period. In most cases, thermal degradation is identified before electrical failure occurs. Insulation stability is another potential submergence issue, but has not been reported as a cause of failures. In the nuclear industry, only one failure in a dc circuit has been attributed to polymer instability. The particular manufacturer's installation was susceptible to instability, and the insulation design was changed. The failure occurred in a situation in which very aggressive, elevated-temperature water surrounded the cable for more than 20 years.

Low-Voltage Power Cables

Low-voltage power cable designs are essentially the same as those of control cables, but have thicker insulations depending on the conductor size. The insulation thicknesses range between 0.045 in. (1.1 mm) and 0.08 in. (2 mm). The insulations are generally XLPE, FR-EPR, EPR/NEO, EPR/CSPE, butyl rubber, and silicone rubber. PVC was used in many non-U.S. plants. The cables are generally rated for 90°C conductor temperatures in a 40°C ambient environment with the exception of butyl rubber and PVC, which have lower thermal ratings, and silicone rubber, which has a conductor rating of 120°C and higher.

The aging concerns for low-voltage power cables are the same as those for control cables.

Appendix D: Bibliography of Reports Related to Condition Monitoring

The technical reports listed in Table D-1 contain information related to condition monitoring. Some of the general information or concepts in them have been included in this report, but no specific references are cited. They can be a useful source of additional background information on various topics that were mentioned in this report.

For a compiled list of references cited in the report, see Appendix E.

Table D-1
Reports Related to Condition Monitoring

Title	Number
Infrared Thermography Guide, Revision 3, 2002	EPRI 1006534
Cable Polymer Aging Database (C-PAD), 2002	EPRI 1001001
How to Conduct Material Condition Inspections, 1994	EPRI TR-104514
Effects of Moisture on the Life of Power Plant Cables, 1994	EPRI TR-103834
Guideline for System Monitoring by System Engineers, 1997	EPRI TR-107668
Improved Conventional Testing of Power Plant Cables, 1996	EPRI TR-105581
Oxidation Induction Time (OIT) for Electric Cable Condition Monitoring and *Life Assessment* (prepared for U.S. DOE, November 1999)	SBIR Status Report
Power Plant Practices to Ensure Cable Operability, 1992	EPRI NP-7485

Appendix E: References

1. *Guideline for the Management of Adverse Localized Equipment Environments*. EPRI, Palo Alto, CA: 1999. TR-109619.
2. *Training Aids for Visual/Tactile Inspection of Electrical Cables for Detection of Aging.* EPRI, Palo Alto, CA and U.S. Department of Energy, Washington, D.C.: 2002. 1001391.
3. *Aging Management Guideline for Commercial Nuclear Power Plants – Electrical Cable and Terminations.* Prepared by Ogden Environmental and Energy Services Company for Department of Energy Technology Management Center, Sandia National Laboratories: September, 1996. SAND96-0344.
4. *A Review of Equipment Aging Theory and Technology.* EPRI, Palo Alto, CA: 1980. NP-1558.
5. *Cable Aging Management Program for D. C. Cook Nuclear Plant, Units 1 and 2.* EPRI, Palo Alto, CA: 1996. TR-106687.
6. *License Renewal Electrical Handbook.* EPRI, Palo Alto, CA: 2001. 1003057.
7. *Cable System Aging Management.* EPRI, Palo Alto, CA: 2002. 1003317.
8. *Diagnostic Matrix for Evaluation of Low-Voltage Electrical Cables.* EPRI, Palo Alto, CA: 1997. TR-106108.
9. *Nuclear Power Plant Common Aging Terminology.* EPRI, Palo Alto, CA: 1992. TR-100844.
10. *Investigation of Bonded Jacket Cable Insulation Failure Mechanisms.* EPRI, Palo Alto, CA: 2002. 1001002.
11. *Evaluation of Cable Polymer Aging Through Indenter Testing of In-Plant and Laboratory-Aged Specimens.* EPRI, Palo Alto, CA: 1996. TR-104075.
12. *Polymer Specimen Removal Techniques for In-Service Cables.* EPRI, Palo Alto, CA: 2000.TR-112233.
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16. *Methodologies and Processes to Optimize Environmental Qualification Replacement Intervals.* EPRI, Palo Alto, CA: 1996. TR-104873.
17. "IEEE-IPCEA Power Cable Ampacities," IEEE S-135 IPCEA P-46-426, 1962, Second Printing, Institute of Electrical and Electronics Engineers, Inc.
18. *Oconee Electrical Component Integrated Plant Assessment and Time Limited Aging Analyses for License Renewal: Parts 1 and 2.* EPRI, Palo Alto, CA: 1998. TR-107527.
19. *Modern Plastics Encyclopedia 1985–1986.* McGraw-Hill Book Company 1987.
20. *Parker O-Ring Handbook.* ORD 5700, Parker Seal Group 1982.
21. *Handbook of Plastics and Elastomers.* Edited by Charles A. Harper, McGraw-Hill Book Company 1975.

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