ELECTRIC POWER RESEARCH INSTITUTE

Low-Voltage and Instrumentation and Control Cable Aging Management Guide, Revision 1

2017 TECHNICAL REPORT

Low-Voltage and Instrumentation and Control Cable Aging Management Guide, Revision 1

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ABSTRACT

Managing cable reliability for nuclear power plant cables increases in importance the longer these plants are operated. This document is the first revision to the guidance EPRI has provided for developing and implementing a cable aging management program for low-voltage power, control and instrument cable circuits in nuclear power plants. Guidance is provided for monitoring cable condition and managing cable reliability by identifying cables located in adverse localized environments and determining if those environments have caused significant cable circuit degradation.

The document describes how to identify the scope of the cable circuits to be evaluated, those conditions that are considered to be adverse environments, and the actions to be taken to assess the conditions of the cable circuits subjected to adverse conditions. Applicable test methodology is described along with possible corrective actions that could be implemented.

This guide describes a common approach for developing and implementing a low-voltage power, control, and instrument cable system aging management program that will identify and resolve cable circuit aging concerns. The focus is on worst-case adverse environmental conditions. Verifying that cables in such conditions are not aging significantly indicates that the cables in less severe environments are in satisfactory condition. If not, the scope of assessment broadens, and further action is needed.

Keywords

Cable aging management
Control cables
Instrument cables
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Power cables

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EXECUTIVE SUMMARY

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Product Title: Low-Voltage and Instrumentation and Control Cable Aging Management Guide, Revision 1

PRIMARY AUDIENCE: Cable program owner engineers

SECONDARY AUDIENCE: System, and component engineers that are affected by the reliability and long term health of cables under their area of responsibility.

KEY RESEARCH QUESTION

What is the most efficient way to manage the reliability of the over 30,000 low-voltage power, control and instrument cables in a nuclear power plant? What are the operating and environmental stressors that result in cable insulation degrading? What condition monitoring tools can be used to evaluate cable degradation for the aging stressor? What actions should be taken if cable degradation is identified?

RESEARCH OVERVIEW

This guide describes how to identify the scope of the cable circuits to be evaluated, those conditions that are considered to be adverse environments, and the actions to be taken to assess the conditions of the cable circuits subjected to adverse conditions. Applicable test methodology is described along with possible corrective actions that could be implemented.

KEY FINDINGS

- Monitoring a small subset of low-voltage cables in nuclear power plants that are in adverse local equipment environments is an efficient way to manage cable degradation and also provides a leading indicator of overall plant cable aging
- Low voltage cable degradation in wet environments is not due to water treeing, but typically due to installation damage or specific insulation type instability in wet environments
- High ambient temperatures (>122˚F (50˚C)) is the predominant stressor for cable aging
- Cable visual inspections is the best method to monitor cable condition for accessible cables or for inaccessible cables inspected during maintenance or other opportunistic inspections
- Jacket polymers are typically leading indicators of cable insulation aging because they degrade (typically harden) faster than the insulation polymer
- Remaining cable life can be evaluated, but typically requires obtaining samples from in-service cables that appear to have degraded

WHY THIS MATTERS

Cable aging management is a key element for maintain current and long term reliability of plant cables.

HOW TO APPLY RESULTS

Cable program owners need to review their current cable program guidance and update it based on this revised guidance and references as appropriate.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- This revision will be discussed at the upcoming EPRI cable user group meeting January 9-11, 2018 during the EPRI cable research update.
- An email will be sent to Cable user group technical advisors and program owners notifying them that the report is available for download.

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INTRODUCTION

This is the first revision to the low voltage cable aging management program guidance. The initial versions of this guide was for program implementation. Originally there were two guides, EPRI 1020804 for low voltage power cable and EPRI 1021629 [1] for instrument and control cables. This revision will combine that guidance into a single document and supersede those guides. This unification will minimize member cost by updating a single report for this and future revisions, if needed. This guide will not have any impact on programs developed under the previous guidance, nor will there be contradictory guidance to that provided in the original reports.

> ***Program Element 1***
>
> Each nuclear power plant should have an aging management program that includes low voltage power, control, and instrument cable circuits. A program plan and implementing procedures should be prepared. Documentation of program development and implementation should be prepared and retained. Program health should be monitored using established performance indicators.

Low Voltage Power Cables

Low voltage power cables (those operating at less than 1000 V)[1] may age and fail due to a number of different mechanisms. Random causes such as installation damage or manufacturing defects do not affect any significant portion of the population of cables. Information on these types of defects can be found in EPRI 3002010637 [3] and therefore are not described in this report. This document pertains to long-term aging that, if neglected, could lead to in-service failures. A separate guide, the Electric Power Research Institute (EPRI) report *Aging Management Program Guidance for Medium-Voltage Cable Systems for Nuclear Power Plants, Revision 1* (3002000557) has been prepared for medium-voltage power cables [4]. It is recognized that plants may choose to have one program cover all cable types. However, because there are different aging mechanisms and assessment activities that apply to medium voltage cables versus low voltage power, control, and instrument cables types, there are separate EPRI guides for them.

In a few plants, the prime movers for safety systems are powered by low-voltage power cable, and failure of these cables may have a significant effect on plant safety and reliability. However, in most plants, the prime movers are powered by medium-voltage cable; therefore, the failures of individual low-voltage power cables generally do not have a crucial effect on plant operation and

[1] Some specialty instrumentation cables may operate at 2 kV and would be considered low-voltage cables. Power cables operating at 2.4 kV to ground are medium-voltage cables.

safety. Failure of an individual instrumentation or control cable generally does not represent a significant risk due to electrical system redundancy and diversity. However, if the aging of cables subjected to adverse environments and service conditions is not controlled, multiple cables could age to the point where safety and reliability could be impacted should a design basis event, or a localized area failure result in a steam or water spray condition. An aging management process for low voltage power, control, and instrument cables systems is desirable to limit the number of in-service failures, and to support high reliability of these cable systems, and ensure accident condition functionality.

Control Cables

An additional class of low-voltage cables exist that support instrument logic and control functions for both ac and dc circuits. These low-voltage cables share many of the attributes of low-voltage power cables.

The following description of *control cables* is found in "The Power Plant Electrical Reference Series, Volume 4 Wire and Cable, EL-5036-V4 [5]:

> Control cables are those applied at relatively low current levels or used for intermittent operation to change the operating status of a utilization device of the plant auxiliary [or safety] systems. They interconnect protective relays, control switches, push buttons, and contacts from various devices [such as connections for interlocks and outputs from auxiliary relays]. Control cables are generally multi-conductor [cables] (for example, 2/C, 3/C, 4/C, 5/C, 7/C, 9/C, 12/C and so on). Control cable is usually rated at a minimum of 600 V.

Control cables typically have conductors that are 14 or 12 AWG (2.08 or 3.31 mm^2). However, 10, 9, 8, or 6 AWG (6.26, 6.63, 8.36, or 13.29 mm^2) may be used in long runs of current transformer or voltage transformer leads. Control circuits are shielded in rare cases. An example would be control cables that are used in 230-kV or higher substations (switchyards).

Instrument Cables

The following description of instrument cable is from the EPRI Report EL-5036-V4 [5]. Text in square brackets has been added to support understandability or to fit the nuclear power context.

> Instrument cable carries low-level analog or digital signals. Low-level analog signals are variable voltage or currents from instrumentation systems. Low-level digital signals are coded voltage signals from analog-to-digital converters or digital computers. Instrument cable is not limited to instrument circuits but is also used in security systems, page-party communications, fire detection, and other systems.[2] In Insulated Cable Engineers Association (ICEA) terminology, instrument cable is called type A control cable. Instrument cables are made in pairs or triads [three twisted singles] and are usually

[2] This is a general definition of instrument cable and is not intended to indicate whether security systems, page-party communications, and fire detection are or are not within scope of the low voltage power, control and instrument cable aging management program. Each plant will determine if these cables are within scope or not.

> specified with a 300-V rating. The pair or triad may be individually shielded, typically with aluminum backed Mylar [polyester] tape with a tinned copper drain wire in contact with the shield. The drain wire is used to terminate the shield. A shield may be provided over all of the pairs [or triads]…"

Conductor sizes for instrument cable are typically 16 or 18 AWG (1.31 or 0.82 mm^2). Some plants have shielded pairs or triads with copper tape or fine parallel wire shields.

Coaxial and triaxial cables and thermocouple extension wire are also included in the instrument cable category.

Aging Stressors

Low-voltage power, control and instrument cables that are properly installed, supported, and kept cool and dry should have a very long life. However, cables that are exposed to adverse conditions that stress the polymers and reduce the useful operating life for these cable types should be subject to aging management. The following are aging stressors with respect to the longevity of low voltage power, control, and instrument cables:

- Adverse localized high ambient temperatures during normal operating conditions
- Adverse localized high-radiation ambient environments under normal operating conditions
- High conductor temperature from ohmic heating (values close to maximum cable rated ampacity levels)
- High-resistance connections at terminations or splices
- Long-term wetting for certain insulation types and applications[3]
- Exposure to chemicals, oils, or hydraulic fluids

Instrument and control cable in switchyards may be located in covered trenches. Rodents can sometimes enter trenches through gaps between covers or by burrowing under trench walls. They tend to chew on cables, damaging the jackets and insulation. If there are indications of rodent intrusion, it is recommended to verify that rodent damage has not occurred. If damage has occurred, appropriate repairs should be made. Coverings are available that may be wrapped around cables to discourage teething on the cables.

The presence or absence of these conditions can be determined by inspection and analysis, environmental monitoring, or infrared thermography. If there are no adverse conditions, a long life can be expected for the cable system. Accordingly, for applications having benign environments and service conditions, monitoring and maintenance are not necessary. Only if failures occur or degradation from extended service (that is, well beyond 60 years) occurs would further action be needed. In that case, the need for maintenance and monitoring for benign environment and service condition applications should be determined in accordance with the Maintenance Rule, 10 CFR 50.65 [6].

[3]Operating experiences for certain insulations, such as high molecular weight polyethylene (HMWPE) and polyvinyl chloride (PVC), may have chemical stability problems. Deterioration of jackets on shielded cable may allow multiple shield grounds under wetted conditions, leading to elevated noise on instrumentation cable. See Section 4 for further discussion.

If one or more adverse conditions are observed, then further assessment, testing and/or corrective action will be necessary to ensure reliability, unless the cable has been designed for the conditions. Actions to be taken for the above conditions will be discussed in Section 5.

Program Development

A program plan or guide should be developed for aging management of low voltage power, control, and instrument cable. The following elements should be considered for the program plan:

- A well-structured process including scoping, identification of adverse environments and service conditions, assessment of cables exposed to the adverse environments and conditions, and implementation of corrective action as appropriate
- A schedule for completion of the scoping and determination of the cables potentially affected by adverse environments and service conditions (see Section 3, Approach to Implementation of Aging Management of Instrument and Control Cable) and development of the initial assessment plan and expected cost for adoption
- Management's objectives for the program (such as identification and management of aging caused by adverse localized environments and adverse service conditions)
- Interfaces with other inspection and integrity programs (for example, infrared thermography program or thermal insulation integrity program)
- Defined roles and responsibilities including program manager, supporting organizations for assessments, tests, and repair and replacement
- Training requirements
- Scope of cables to be included in the program (see Section 2, Scope of Aging Management for Instrument and Control Low-Voltage Power Cable Systems)
- Management sponsorship of continued implementation
- Program health reporting and corresponding performance indicators
- Documentation to be retained including scope determination, adverse service conditions, cables to be assessed,[4] condition and cable assessment methods, condition and cable assessment and test results, and corrective actions that have been implemented

[4] When the cable aging assessment starts when identifying the adverse environments and it is determined whether the cables experiencing adverse environments have aged, the cables to be assessed may be identified in terms of trays or conduits containing cables at a specific location, rather than in terms of individual cable circuits. Individual circuit identifications must be determined only when cable aging has been determined to be significant. Periodic assessment of the cables at the location of the adverse environment should continue until degradation has become significant—at which point the individual circuits must be identified—or until the cause of the adverse environment has been corrected.

Implementing Procedures

Implementing procedures[5] should address the following:

- Roles and responsibilities
- Scoping methodology and documentation
- Identification of adverse conditions
- Consideration of susceptibility of the plant cables to adverse conditions
- Identification of cables needing assessment
- Schedule of initial assessments and subsequent periodicity of assessment
- Methods to be used to assess cables subjected to adverse conditions
- Assessment of results related to cable condition
- Repair or replacement options (See Section 7, Actions for Failed or Deteriorated Cable)
- Program peer or self-assessment periodicity

Data and Information to Be Collected and Retained

The following data and information should be retained for use in continued assessment:

- Program plan
- Implementing procedures
- Scope of the program
- Cables within the program that are subjected to adverse localized environments and/or service conditions that need aging management
- Additional information that should be identified for these cables includes the following:
  - The nature and location of adverse environment or service conditions.
  - The cable circuits that are affected, including subcomponent of concern (for example, termination, splice, or cable). Specific cable circuits may not have to be identified until the degradation is severe enough to affect function or accident survival capability. For example, an adverse environment, such as a pipe with elevated temperature, may be found to be having an effect on cables in an adjacent tray, but the effect may not yet warrant action. In this case, identification of the specific circuits is not yet necessary. The information to be recorded would be the location of the adverse environment and the tray of cables that is to be periodically assessed. (See Footnote 4.)
  - The associated application of affected cable circuits (for example, power or control cable; controlled load, or instrument application; controlled load), in cases where specific circuits are identified.

[5] Different utilities use the terms *guides, procedures*, and *plans* in different ways. The key issue is to have a documented process that includes the appropriate elements of a cable aging management program.

  - The degradation mechanism of concern (for example, thermal damage or voltage/water degradation).
  - The means of assessing or monitoring the effect, and the periodicity of assessment (for example, one-time assessment, periodic visual inspection, or periodic test [including initial planned assessment interval]).
  - The methodology of assessment and tests. (Given that periods between assessments and tests may be a number of years, a complete description of the methods used will help to ensure the ability to compare and trend results, especially if changes to methods occur as technology improves.)
  - The results of assessments and tests.
  - Repair and replacement descriptions.
- When credit is taken for maintaining dry conditions in ducts, manholes, and vaults, documentation showing that automatic drainage systems are effective and/or that cables are not found to be submerged when water is manually pumped from manholes and vaults.
- Program health report performance indicators.

Program Plan Milestones

The following are suggested program plan milestones:

- Program plan and technical procedures are in place, current, and being implemented.
- Program documentation is complete and current.
- Roles and responsibilities are defined, accepted, and owned by organizations and individuals for assessment, testing, repair and replacement.
- The program manager and backup are identified and trained.
- Program resources are determined to be adequate.
- The scope of the program is clearly defined.
- The cables within the scope of the program have been identified.
- The potentially adverse localized environments and adverse service conditions of concern have been defined.
- The cables within the program that are subjected to potentially adverse localized environments and/or adverse service conditions have been identified for further assessment.
- For cables requiring further assessment, a means of assessing the cable has been identified and scheduled.

Program Health Indicators

The following are possible program health indicators:

- The cable circuit/adverse environment assessments are being implemented according to schedule.
- Deferrals of cable circuit assessments are limited.
- Review of cable circuit assessment results is timely, and corrective actions are initiated.
- Implementation schedule of corrective actions is met.
- Prevention of cable submergence is satisfactory.
- Control of thermal insulation in the vicinity of power cable is adequate.
- Program self-assessments are being performed at a reasonable interval.
- The number of open findings or areas for improvement from internal or external audits or assessments (such as those from the U.S. Nuclear Regulatory Commission or the Institute of Nuclear Power Operations) is limited and the findings are being resolved satisfactorily and in a timely manner.
- Forensic assessment of cables that fail in service is being conducted. If the findings indicate changes or improvements to the program, those changes or improvements are being planned or implemented.
- Applicable operating experience from other plant sites is being reviewed, assessed, and incorporated into the cable system aging management program by the program manager.

Definitions

Assessment. In this report, the word *assessment* is used to cover a broad range of activities regarding cable circuit condition. These activities include evaluating the severity of environments and service conditions, evaluating the need for testing, and evaluating condition, including visual/tactile inspection and condition monitoring through activities such as electrical testing or *in situ* or laboratory physiochemical testing. Some assessments are expected to limit the scope of testing and evaluation (for example, the cable has benign service and environmental conditions); other assessments will include testing and condition monitoring, as appropriate, due to the presence of adverse service or environmental conditions.

Wet, Damp, and Dry Locations. Both Underwriters Laboratories and the National Electric Code define the terms *dry, damp,* and *wet* locations (see Table 1-1). The definitions indicate that the term *wet* means up to and including submerged, and not just *damp,* which has its own definition. The National Electric Code definition of *wet location* indicates "… subject to saturation with water or other liquid…." The Underwriters Laboratories definition indicates "… liquid can drip, splash, or flow on or against electrical equipment."

Table 1-1
National Electrical Code and Underwriters Laboratories Definitions of Dry, Damp, and Wet Locations

Term	National Electrical Code Definition [3]	Underwriters Laboratories Definition [4]
Dry Location	A location not normally subject to dampness or wetness. A location classified as dry may be temporarily subject to dampness or wetness, as in the case of a building under construction.	A location not normally subject to dampness, but may include a location subject to temporary dampness, as in the case of a building under construction, provided ventilation is adequate to prevent an accumulation of moisture.
Damp Location	Locations protected from weather and not subject to saturation with water or other liquids but subject to moderate degrees of moisture. Examples of such locations include partially protected locations under canopies, marquees, roofed open porches, and like locations, and interior locations subject to moderated degrees of moisture, such as basements, some barns, and some cold storage buildings.	An exterior or interior location that is normally or periodically subject to condensation of moisture in, on, or adjacent to, electrical equipment, and includes partially protected locations.
Wet Location	Installations underground or in concrete slabs or masonry in direct contact with the earth; in locations subject to saturation with water or other liquids, such as vehicle washing areas; and in unprotected locations exposed to weather.	A location in which water or other liquid can drip, splash, or flow on or against electrical equipment.

Inaccessible Cables. *Inaccessible cables* are those cables that have sections located below grade or embedded in the plant base mat; that are located in conduits, duct banks, buried conduits, cable trenches, cable troughs, or underground vaults; or that are direct buried. [6]

The concept of inaccessibility for cables is related to the ability to determine environments and physical condition of cable. For underground cable, inaccessibility makes identification of wetting and submergence more difficult. In dry plant areas, inaccessibility is less of a problem. Even when cables are inside conduits or contained in trays that are difficult to access, identification of heat sources that are close to the tray or conduit is relatively easy, and determining the need for further assessment of condition is possible. Inaccessibility is not a concern if adverse service conditions and environments do not exist.

[6] *NUREG-1801, Generic Aging Lessons Learned Report,* Section XI.E3, Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements, states "…inaccessible (e.g., in conduit or direct buried) medium-voltage cables…." [7]. *NRC Generic Letter 2007-01* states "…in inaccessible locations such as buried conduits, cable trenches, cable troughs, above ground and underground duct banks, underground vaults, and direct-buried installations" [8].

Abbreviations and Acronyms

The following abbreviations and acronyms are used in this report:

ac	alternating current
dc	direct current
CSPE	chlorosulfonated polyethylene (commonly referred to by the DuPont trade name, Hypalon)
EPR	ethylene propylene rubber
EPR/CSPE	Composite insulation having EPR as the primary insulation with a layer of CSPE applied over the EPR to add fire retardancy. The CSPE layer may or may not be bonded to the EPR.
FDR	Frequency domain reflectometry
Gy	Gray; a metric unit of radiation equal to 100 rad
hr	hour
ICEA	Insulated Cable Engineers Association
MGy	Megagray
Mrd	megarad
PVC	polyvinyl chloride
rd	rad
TDR	time-domain reflectometry
XLPE	cross-linked polyethylene

2
SCOPE OF AGING MANAGEMENT FOR LOW-VOLTAGE POWER CONTROL AND INSTRUMENT CABLE SYSTEMS

Program Element 2

The cables and associated connections and terminations that support the function of Maintenance Rule equipment should be within the scope of the low-voltage power, control and instrument cable aging management program. It is recommended that additional cables associated with the scope of the License Renewal Program be included in this cable aging management program. These cable circuits may be included in the initial scope or added to the program when implementation of License Renewal actions is required. Any commitments related to low-voltage power, control and instrument cable's aging management contained in plant-specific regulatory correspondence should also be included in the development of the program and its scope.

Cables required to support critical functions as defined in AP-913, *Equipment Reliability Process*, should be considered for inclusion in the scope of the low-voltage power, control and instrument cable system aging management program. Any of the low-voltage power, control and instrument cables critical to power generation may be added to the scope of the program at management's discretion.

The development of the scope of the cable circuits to be within the low voltage power, control, and instrument cable system aging management program should consider these sources:

- The Maintenance Rule, 10 CFR 50.65 [6]
- The License Renewal Rule, and Subsequent License Renewal Rule 10 CFR 54 [9]
- Updated Final Safety Analysis Report commitments (if any)
- Plant-specific licensing commitments
- License Renewal Aging Management Program commitments
- Critical components as defined in INPO AP-913, *Equipment Reliability Process* [10]
- Circuits critical to power generation (management option)

Table 2-1 provides a comparison of the equipment covered by the Maintenance Rule, 10 CFR 50.65, and the License Renewal Rule, 10 CFR 54. Paragraph 10 CFR 50.65(b)(1) and paragraph 10 CFR 54.4(a)(1) require that cables supporting safety-related functions be within scope of the respective activities. Paragraphs 10 CFR 50.65(b)(2) and 10 CFR 54.4(a)(2) both require that non-safety-related cables whose failure could prevent safety-related functions from being fulfilled be within scope. Paragraph 10 CFR 50.65 (b)(2) also requires that cables used to mitigate accidents or transients or to support emergency operating procedures, as well as cables whose failure could cause a reactor scram or actuation of a safety-related system, be in scope. Paragraph 10 CFR 54.4(a)(3) extends beyond the Maintenance Rule scope in that cables related to Station Blackout and Fire Protection are within scope.

Some plants may have cable monitoring commitments in their updated final safety analysis report. All plants will have cable aging management commitments in the License Renewal aging management program for cable and for connections and terminations. There are likely to be separate aging management programs for cable and for connections and terminations that should be considered when developing the scope and content of the low voltage power, control and instrument cable aging management program.

Some plants may have cable-specific regulatory correspondence pertaining to cable that should be considered when setting the scope of the aging management program. Review of the plant-specific response to Generic Letter 2007-01 [8] is appropriate to confirm the activities that the plant stated were in place to assess the condition of cables and to control wetting of cables. As the plant's low-voltage ac and dc power cable system aging management program is developed and implemented, it is recommended that differences from and changes to methodologies from those in the Generic Letter 2007-01 response be documented.

The AP-913 equipment reliability process ranks components with respect to importance to reliability. Those cables that support the function of critical components should be considered with respect to the scope of the low voltage power, control cable aging management program.

Table 2-1
Scope Comparison for Maintenance Rule, 10 CFR 50.65, and License Renewal Rule (10 CFR 54) [5, 9]

Maintenance Rule Scope	License Renewal Scope	Differences
10 CFR 50.65(b)(1) Safety-related…systems and components that are relied upon to remain functional during and following design basis events to ensure the integrity of the reactor coolant pressure boundary, the capability to shut down the reactor and maintain it in a safe shutdown condition, or the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure….	10 CFR 54.4(a)(1) Safety related systems, structures, and components which are those relied upon to remain functional during and following design-basis events (as defined in 10 CFR 50.49(b)(1)) to ensure the following functions— (i) The integrity of the reactor coolant pressure boundary; (ii) The capability to shut down the reactor and maintain it in a safe shutdown condition; or (iii) The capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the guidelines in 10 CFR 50.34(a)(1), in 10 CFR 50.67(b)(2) or 10 CFR 100.11 of this chapter as applicable.	None.
10 CFR 50.65(b)(2) Non-safety related…systems, or components: (i) That are relied upon to mitigate accidents or transients or are used in plant emergency operating procedures (EOPs); or (ii) Whose failure could prevent safety-related structures, systems, and components from fulfilling their safety-related function; or (iii) Whose failure could cause a reactor scram or actuation of a safety-related system.	10 CFR 54.4(a)(2) All non-safety related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1)(i), (ii), or (iii) of this section. 10 CFR 54.4(a)(3) All systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63)	Agreement on non-safety-related components that could affect function of safety components. Maintenance Rule adds cables associated with emergency operating procedures and that could result in scrams or safety system actuation. License Rule adds cables associated with fire protection and station blackout. (Environmentally qualified cables would be in scope already; it is not clear whether any cables are associated with pressurized thermal shock or anticipated transients without scram.)

Program Scope Versus Cables Requiring Condition Monitoring or Assessment

The purpose of scoping is to identify cables that, if exposed to adverse environments or adverse operating conditions, will have their condition assessed or monitored. It is not the intent of the program to assess and monitor the condition of every cable circuit. Rather, this document recommends assessment of cables and the associated splices and terminations that are exposed to adverse environments or that have adverse service conditions. Accordingly, those cable circuits that are within the scope, such as those supporting Maintenance Rule functions, **and** that are exposed to adverse environments or adverse service conditions, will be assessed or monitored under the low voltage power, control, and instrument cable aging management program as appropriate.

For low voltage power, control, and instrument cables, plants may determine a list of cables to be assessed from single line diagrams or from a raceway routing database and then determine whether these cables are subjected to adverse conditions. Alternatively, one could determine the locations of adverse localized environments that could age the cables prematurely and then assess the conditions of cables in those locations. Where significant degradation is detected, action is expected to be taken either to correct the condition or to replace or repair the cable. Figure 2-1 illustrates the scoping concept. Although this document focuses on managing the aging of low voltage power, control, and instrument cable circuits that are subject to recognized adverse effects, the Maintenance Rule process ensures that if a new failure cause is identified, it will be assessed, and corrective actions will be taken to control the effect. As appropriate, the cable system aging management program should be revised to take new failure causes into account.

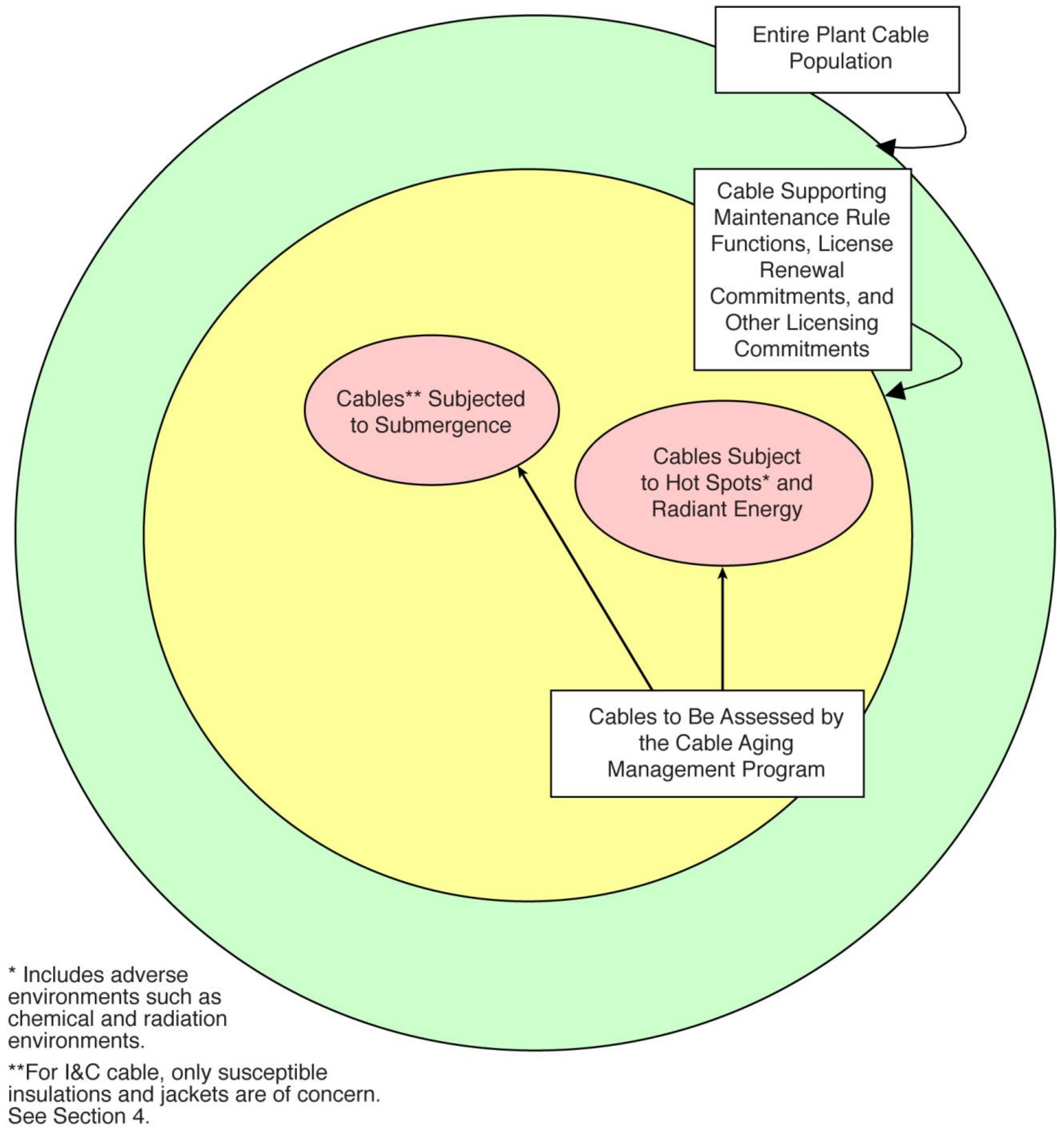

Figure 2-1
Low voltage power, control, and instrument Cable Scoping Process

3
APPROACH TO IMPLEMENTATION OF AGING MANAGEMENT OF LOW VOLTAGE POWER, CONTROL AND INSTRUMENT CABLE

Program Element 3

The subset of cables within the scope requiring assessment should be determined by identifying the adverse localized environments and then determining whether cables are aging prematurely in those areas.

The number of low voltage power, control and instrument cables in dry conditions within the plant is large. Accordingly, focusing on aging of cables in adverse localized environments is appropriate to limit aging management to those cables that are subjected to conditions that could cause premature aging. Focusing on worst-case applications and determining whether aging is occurring in those cables provides a basis for understanding the overall health of the low voltage power, control and instrument cable systems. If significant aging were found in the worst-case circuits, appropriate corrective action would be implemented, and the assessment of low voltage power, control and instrument cables, as applicable, would be widened to take in similar cable types in the next most severe adverse environment of concern. This process would continue until the next most severe adverse environment in question's condition is assessed as not detrimental to cable aging.

This approach is conservative with respect to Maintenance Rule requirements [6] and AP-913 equipment reliability goals [10] in that cables that are not at risk of premature aging and, accordingly, not affecting system performance would not have to be assessed. Evaluation of worst-case cables, including circuits having past failures, if any, would support early identification of problems and broadening of the review if significant aging were identified, thus supporting system performance and reliability before it deteriorated.

Given the large number of low voltage power, control and instrument circuits in a nuclear plant, identifying the areas within the plant having adverse localized environments and then determining whether in-scope cables are affected by the adverse localized environments is the most appropriate method to use. With this method, the areas with adverse environments would first be identified. Then, the areas would be evaluated—either physically or through use of plant raceway drawings, or both—to determine whether low voltage power, control and instrument cables are in the vicinity of the adverse localized environments. Walkdowns could be used to determine whether low voltage power, control and instrument cables are potentially affected and, if so, they would be evaluated through visual/tactile assessment or other appropriate means. If no significant degradation is identified, then identification of specific circuits would not be necessary. If significant degradation is identified, then identification of specific circuits and appropriate corrective action would be necessary. Guidance on performing walkdowns for identification of adverse localized environments is contained in the EPRI report Guideline for the Management of Adverse Localized Equipment Environments (TR-109619) [12]. The need for periodic walkdowns is a plant-by-plant consideration.

Another concept that can be used to inform the scope of cables that may be good indicators of cable aging would be the use of opportunistic inspections of cables during maintenance. There are many examples of normally inaccessible cables in a variety of operating environments that are occasionally made accessible for routine preventive or corrective maintenance. This would include cables in manholes, junction boxes, transformer control cabinets, bus and breaker cubicles, motor control centers, electrical penetrations, motor operated valve operators, etc. Adding a cable inspection activity for visual tactile examination in applicable library preventive maintenance task, or identifying specific corrective maintenance work orders for a knowledgeable individual to observe, photograph and identify the condition of these cables could prove to be a valuable addition, or even equivalent activity to performing plant walkdowns where limited visual access of cables can be made.

Underground ducts, vaults, and manholes that are wet should be considered adverse environments. Instrument and control cables that are currently submerged or have been submerged for extended periods should be evaluated to determine whether significant aging has occurred. The evaluation should consider plant operating experience, the type of insulation used in the cable, and the design and application of the cable. A few cases of water-related degradation have occurred in insulations that used certain early insulating materials produced in the late 1960s (PVC, high molecular weight polyethylene, or a specific radiation-cured cross-linked polyethylene [XLPE]), although even these occurrences are rare. No generic wet aging mechanism under low-voltage excitation is known for ethylene propylene rubbers (EPRs) and XLPE insulations that became available for use in the early 1970s. Jacket deterioration on shielded cables may cause multiple grounds on instrument cable shields, leading to circuit noise. Section 4 describes these conditions and how to address them.

If underground ducts, vaults, and manholes are dry, then no adverse environment exists.

4 IDENTIFICATION OF ADVERSE ENVIRONMENTS AND CONDITIONS

Program Element 4

The program should identify those conditions that are considered to be adverse localized environments. This determination should consider elevated temperature, radiant heating from exposed process piping, radiation, water, chemical, and oil exposure.

In establishing the program, the severity of environmental parameters and the associated duration at which aging would become a concern should be established. For example, the temperature above which aging would be a concern for a 40- or 60-year life could be established, or the radiation dose for a given life could be established. It is recommended that conservative values be assumed initially, with revisions being allowed as experience is gained. The intent is not to assess all cable circuits exposed to the elevated stress levels, but rather to identify areas of potential concern within the plant. Evaluation of the population of worst-case applications will provide the insight necessary to determine when assessment of additional cables in less adverse environments is necessary.

The program should verify that adequate controls exist on verification of the condition or require a review of ohmic heating documentation to determine whether significant aging from ohmic heating for low-voltage power cables is a concern, especially if sections of the cable are located in areas with adverse localized environments.

The thermal insulation on hot process piping and equipment in the vicinity of low voltage power, control, and instrument cables is necessary to limit thermal aging that would reduce cable life. If temporary removal of thermal insulation at power is part of the maintenance strategy for the plant, the program should specify that the insulation not be removed in the vicinity of cable or, if it will be, that the effects of the resulting thermal aging be evaluated and controlled.

EPRI report TR-109619 provides guidance on identifying adverse localized equipment environments [12]. The report defines an adverse localized equipment environment as an environmental[7] "condition in a limited plant area containing a piece or pieces of equipment that is significantly more severe than the specified service conditions for the equipment, the room in which the equipment is located, or the surrounding plant area. The service conditions of interest include normal, abnormal, and error-induced conditions prior to the start of a design-basis accident or earthquake."

[7] The words *an environmental* were added for clarity in this report. They are not included in the original definition.

Adverse environmental conditions for low voltage power, control and instrument cables are the following:

- High temperature or radiation dose rate environments under normal operating conditions
- Long-term wetting with respect to certain insulation types and applications
- Chemical or moist environments (a concern for unsealed terminations, such as at terminal blocks)
- Oil or hydraulic fluid contamination
- Environmentally induced corrosion or deterioration of connections, terminations, or connector assemblies, including connector seals

Identification of Adverse Environments

Temperature

Elevated temperature is likely to be the most common cause of long-term aging of cable insulations and jackets, connectors, and splices in normally dry areas. For most insulation types and jackets used in nuclear plants, thermal aging causes the materials to harden, lose elongation properties, and eventually lose tensile properties. Similarly, thermal aging may lead to loss of seal integrity in connectors and splices.

For power cables, whether ac or dc, the combination of ohmic heating from load current and ambient environment temperature affects the rate of aging of the insulation and jacket systems. For low-voltage power cables, operational ratings are based on a maximum conductor temperature in an assumed 104°F (40°C) ambient environment. Most power cables have 90°C conductor temperature ratings (ampacity). Power cable in areas with high ambient temperature (that is, in excess of 104°F [40°C]) will tend to thermally age more rapidly if operated close to ampacity if the elevated ambient temperature was not considered in the design.

As ambient temperature increases above 122°F (50°C), the jacket materials of some low voltage power, control and instrument cables will begin to thermally age. At 122°F, the aging will take decades. As the temperature increases above 122°F, the effects increase exponentially, and at very high temperatures, aging degradation may occur in a decade or less with or without the ohmic heating. Finding a hardened cable jacket would indicate that assessment of the aging of the cable is desirable to determine if cable is susceptible to cracking and failure. Table 4-1 provides approximate times to the point at which jacket aging would be detectable through tactile assessment for various ambient temperatures. The values are given to show that elevated temperatures reduce life and that jacket materials age at differing rates. The table gives a rough indication of temperature sensitivity for identifying areas where cable condition should be assessed. Graphic presentations of life versus temperature are provided in Appendix A for neoprene and CSPE.

Table 4-1
Approximate Times at Which Jacket Aging Would Be Readily Detectable (Appreciably Hardened)

Material (Note 1)	122°F (50°C)	140°F (60°C)	158°F (70°C)
Neoprene	16–20 years	2–3 years	Very short
Chlorosulfonated Polyethylene (CSPE; often referred to as Hypalon)	>>40 years	25–30 years	10–15 years
Polyvinyl Chloride (PVC; see note 2)	14–22 years	5–8 years	2–3 years

Notes:
1. Manufacturer-specific materials may age more slowly. The times listed were chosen as conservative for the generic material type.
2. There are many PVC formulations having different capabilities. The data presented are for the more susceptible formulations.

The conductor current in most instrumentation and control cables is low, and ohmic heating is not a concern. Thermal damage for these cables is caused by ambient temperature and radiant energy. In general, jacket aging will proceed in advance of insulation aging, and the jacket will be a useful indicator of thermal aging. In the case of composite insulations (for example, EPR with a bonded CSPE layer), aging of the bonded CSPE layer will proceed at approximately the same rate as aging of the overall jacket. Silicone rubber cables tend to be the exception because the jackets are generally braided glass or asbestos that does not degrade under thermal aging. The braided jackets do not provide an indication of thermal aging; however, the high temperature ratings of silicone rubber make thermal aging a limited concern.

The Table 4-1 data provide an indication of the aging of materials based on air temperature. However, radiant heating can also greatly shorten the life of cable jackets and insulation. When cables are not shielded from direct exposure to hot process piping, the cables are also subjected to radiant heating, which greatly increases the rate of aging. Verification that necessary thermal insulation is in place on process piping in the vicinity of low voltage power, control and instrument cable is important. Leaving thermal insulation off process piping can cause significant cable jacket aging in as little as one operating cycle. Some plants have implemented temporary removal of thermal insulation from process piping and components well before the start of refueling outages to reduce workload during the outage and, similarly, reinstall the thermal insulation well after startup. Such actions must be precluded in the vicinity of cable or assessed for the potential for causing early aging of the cable jacket and insulation. Maintaining the condition and control of thermal insulation on process piping in the vicinity of low voltage power, control and instrument cables is important to cable circuit longevity.

Table 4-2 lists some of the areas where elevated temperatures could be expected within a plant. These areas constitute many of the spaces where control of thermal insulation on process piping is desirable.

Table 4-2
Plant Areas and Components with Potentially Adverse Thermal Conditions

Vicinity of main steam lines, including isolation valves
Main steam tunnel
Vicinity of PWR primary loop piping
Vicinity of PWR steam generator and main steam lines
Vicinity of PWR steam generator blowdown lines
PWR pressurizer room
Steam turbine rooms (high-pressure coolant injection, reactor core isolation cooling, feedwater, and auxiliary feedwater)
Feedwater heater bay rooms
BWR turbine bypass valve room
Cables under the reactor (BWRs, Mark I)
Motor and air-operated valves on primary piping
Adjacent to high-temperature lighting fixtures
Motor termination housings for continuous duty motors
Lagging area below the generator and turbine
Vicinity of auxiliary boiler room and associated piping
PWR reactor head
BWR reactor bottom

Radiation

With respect to radiation effects, most low voltage power, control and instrument will be in low-dose areas of the plant. EPRI report 3002010404 [13] contains temperature and radiation data collected from a General Electric boiling water reactor (BWR), a Westinghouse pressurized water reactor (PWR) and a European PWR (VVER) that indicates radiation levels in cable locations are typically much lower by two or more orders of magnitude than levels used for equipment qualification for 40 or 60 years. Using the Westinghouse PWR as an example, in containment 40 year projected radiation levels ranged from .7 Mrd (.7 kGy) to 4 Mrd (40 kGy). The highest 80 year projected radiation dose equates to 16 Mrd (160 kGy). While this is a small dataset of information, there are similarities between the findings at the three plants that provided the data for the report. However, some cables may be located in areas with appreciable doses. Sandia research showed that effects on physical properties are not observable at 1 Mrd (10 kGy) and that at least 5 Mrd (50 kGy) must be absorbed for effects to be observable [14]. Assuming a 60-year desired life for a low-voltage cable, no appreciable effect would be expected for average dose rates up to 10 rd/hr (0.1 Gy/hr). [8] Although minimal effects are expected at 10 rd/hr, the effects could be appreciable if the cables are simultaneously exposed to high temperature (for

[8] 10 rd/hr ≈ 5 Mrd ÷ (60 years × (365 days/year) × 24 hours/day)

example, greater than 122°F (50°C). EPRI report 3002010404 [13] results indicate that this is quite rare. For example, the Westinghouse PWR temperature data from the report had only 1 location at 132.8°F (56°C), which was above 122°F (50°C). The remaining containment temperature values ranged from a low of 76.5°F (24.7°C) to a high of 115°F (46°C).

The effects of radiation and temperature are to change the physical properties (loss of elongation and increased hardness) of the insulation and, after severe aging (such as after cracking), to eventually affect the electrical properties. If high-temperature conditions and radiation doses in excess of 5 Mrd (50 kGy) are expected, the low voltage power, control and instrument cables should be inspected periodically for degradation unless environmental qualification data exist that show the capability of the materials. Until the dose from the exposure reaches approximately 5 Mrd, radiation effects may not be observable. Inspections at the 30 or 40-year mark may identify radiation effects only if the dose rate is well above 10 rd/hr (that is, 15–20 rd/hr).

Although most insulations will harden with exposure to elevated temperature and radiation, PVC hardens with elevated temperature exposure, but does not harden with radiation exposure. Rather, it generates hydrogen chloride (HCl) in its structure when highly irradiated (35–50 Mrd [350–500 kGy]) and the insulation becomes conductive when exposed to steam environments. Although PVC insulation is rarely used in U.S. power cable applications, some non-U.S. plants have significant quantities of PVC-insulated cable. Tefzel-insulated instrument and control cables are in use at some plants. Tefzel insulation is significantly affected by low-dose irradiation when the cumulative dose exceeds 5 Mrd (50 kGy). However, some devices having Tefzel have been environmentally qualified for up to 200 Mrd (2 MGy).

Many types of low voltage power, control, and instrument cable have been subjected to environmental qualification testing. These tests provide information on whether radiation doses up to 50 Mrd (500 kGy or ~95 rd/hr (0.95 Gy/hr) for 60 years) are within the qualification limits for normal aging. The thicker insulation and jackets of low-voltage power cables makes them less susceptible to thermal and radiation aging than the typical qualification sample. The damage from irradiation does not appreciably reduce the electrical properties of the insulation; rather, it hardens the insulation and makes it more susceptible to physical damage and failure after severe degradation. The sole exception is PVC. Where radiation and/or thermal damage are a concern, initial evaluation should include visual/tactile assessment as described in Section 5, Actions for Dry Cables Having Adverse Environments.

Radiation zone maps and environmental reports should be reviewed to determine whether there are any additional zones where high radiation may exist (>5 Mrd/plant life [>50 kGy/plant life]). This data can be seen as bounding, but as found in the EPRI report [13] actual radiation and temperature data collection may be useful to truly understand the cable operating environments.

For cable types having an IEEE Std. 323/383 environmental qualification, radiation qualification may be used to exempt cables from normal radiation exposure consideration for radiation doses within the bounds of the environmental qualification.

Wet Conditions

Multiple concerns exist in association with wet conditions. One is moisture in the vicinity of open connections (that is, terminal blocks). Under moist conditions, corrosion of terminations is possible. Damp terminal blocks may also be subject to surface tracking that can lead to failure. Connections in damp areas, such as intake structures, should be included in assessments.

A second concern is long-term wetting of cable as could occur in underground applications. The literature is silent on the existence of a generic failure mechanism for wet aging of low-voltage insulations. The voltage stress in the low voltage power, control, and instrument cable insulation is < 5 volts per mil (< 19.6 kV/mm) and thus too low to induce electrochemical deterioration (water treeing). A few plants' operating experience identified some very early insulations that have experienced water-related degradations under dc excitation. These are described later in this section. Cable manufacturers perform water stability tests of their insulation systems to verify that the insulations are chemically stable in long-term wetting and submergence conditions. In addition, EPRI performed low voltage cable wet stability research [15] which subjected various, commonly used low voltage cable types to submergence in 194°F (90°C) water for one year under both ac and dc voltages without a single insulation failure.

Although insulation degradation does not appear to be a significant concern, vigilance is recommended. If a low voltage power, control, and instrument cable fails in service, identification of the cause is recommended to determine whether the failure was related to wet aging. Operating experience from other plants concerning wet instrument and control cable failures should be reviewed for applicability. If water-related degradation becomes a concern for a specific type of cable, insulation resistance testing should be considered for a sample of the cable circuits of the same type that are wet to determine the importance of the concern.

For shielded instrumentation cable in wet conditions, water may migrate through jackets after long periods. This may lead to multiple grounds on the shield leading to elevated noise. If noise occurs on underground shielded instrument circuits, keeping the duct and manhole system dry would be one way to eliminate multiple grounds on the shield.

Splices and connectors that are subjected to wet conditions should be considered to be in adverse environments and should be evaluated.

Cables with Known Susceptibility to Wet Aging

Clay-filled XLPE, such as Vulkene, may be susceptible to wet aging, as high molecular weight polyethylene (HMWPE) would be. These were produced in the late 1960s and very early 1970s and rarely used in nuclear plants. An early irradiation cured XLPE[9] also experienced water-related degradation in a dc application. PVC-insulated wires undergo irreversible chemical changes after long-term water exposure. Drying may not improve the electrical properties of the PVC insulation.

[9] This cable type predates the current Rockbestos Firewall III irradiation-cured insulation. Firewall III is not susceptible to water-related degradation.

Plants that were constructed in the late 1960s and very early 1970s may have some of these cable types. License renewal activities have identified the types of cables installed at the plants. If one of these insulation types has been identified at the plant, a review should be performed to determine if low voltage power, control, and instrument cables with that insulation were subjected to submergence. If so, insulation resistance testing of a sample of those cables is recommended to assess cable condition.

Chemical and Oil Contamination

Most low voltage power, control, and instrument cables are not subject to contamination with oil or chemicals. Areas containing borates or other chemicals should be identified and evaluated for having cables nearby. However, with respect to borates, deterioration of exposed terminations is more of a concern than deterioration of the jacket or insulation. For the insulation and jacket systems in use at nuclear plants, borates have little effect on the mechanical and electrical capability of the materials [16].

In general, contamination with oil or hydraulic fluid is related to a spill or leak. Cables subjected to oil or hydraulic fluid contamination should be cleaned and evaluated for any effects on longevity. The effect on the cable jacket and insulation is a factor of the insulation or jacket material, the duration of exposure, the temperature, and the nature of the oil or hydraulic fluid. Short exposures (days) at normal operating temperatures (that is, below 122°F [50°C]) before cleaning will generally not degrade the cable materials. However, short exposures to certain hydraulic fluids at temperatures of 176°F (80°C) or more could significantly plasticize (soften) insulations or jackets and lead to the potential for failure. Long exposure under less severe temperatures may lead to softening or swelling of jacket and insulation materials. If significant swelling or softening of a jacket is observed, removal of the jacket may be necessary to determine the effect on the insulation. If the insulation is not affected, and only a short section of jacket had to be removed, repair of the jacket with heat-shrink material may be possible. If the insulation is significantly degraded, the affected section of cable should be replaced.

Literature searches may provide insights on the effects of chemicals, hydraulic fluid, or oils on specific cable insulation and jacketing systems. If limited or no significant effect is immediately identified after oil, hydraulic fluid, or chemicals are removed from a cable jacket, re-inspection after an operating cycle is recommended to verify that damage that initially was undetectable has not occurred.

Identification of Adverse Service Conditions

Ohmic Heating

The current in the conductors of power cable will cause temperature rise due to ohmic heating. The review of the effects of ohmic heating requires identification of the power circuits and evaluating the current with respect to the ampacities of the cables. If the normal conservatisms were applied during design, cables would be loaded to no more than 80% of ampacity. Given that temperature rise is proportional to the square of the current, 80% of ampacity should result in 64% of the allowed temperature rise. In the case of a 90°C rated cable in a 40°C environment, the rise at 80% ampacity should be approximately 32°C, so that the conductor temperature would be 72°C. Ohmic heating reviews may already exist at plants as part of the cable management system. If so, the existing data should be reviewed to determine the worst cases and whether these cases raise aging concerns. If aging concerns are identified, the cables should be assessed to determine whether premature aging is occurring.

Ohmic heating should be considered in conjunction with identified adverse thermal conditions in rooms, especially if ambient temperature coupled with the conductor rise result in temperatures approaching the rated temperature of the cable.

Periodicity of Review

Ohmic heating reviews need be performed only once unless plant modifications cause an increase to the loading of power cables.

High-Resistance Connections and Terminations or Splices

Most connections and terminations for low voltage control and instrument circuits should pose no aging problems from ohmic heating. Ohmic heating is typically only a concern for low voltage power cables. Some control cables and some instrument cables terminate in multi-pin, coaxial, or triaxial connectors. These connectors are designed to keep the contact system and insulators shielded from outside contaminants. Functional verifications should be sufficient to confirm adequacy of the connection for most circuits. If in the course of identification of adverse environmental conditions, connectors are found to be exposed to adverse environments such as high temperature or radiation conditions, wetting, or chemical, oil, or hydraulic fluid exposure, the condition and functionality of the connector should be assessed.

Quick-break disconnect connectors are becoming more common for circuits in which disconnection of the end device is necessary for maintenance or calibration. Various insert types are available that provide seal and contact support systems. High-temperature connectors generally use a high-temperature insert such as silicone rubber or polysulfone. Lower-temperature connectors may have neoprene inserts. Care must be taken not to use neoprene inserts in applications with elevated temperatures (such as 158°F [60°C] or greater), because when severely aged, neoprene becomes conductive and will cause shorting of the circuit.

Tape and heat-shrink splices should likewise protect the connections; however, if they are found to be in adverse environments, their condition should be assessed.

Terminal block connections by nature are expected to be kept dry to maintain functionality. Terminal blocks are generally manufactured of materials that have good aging characteristics with respect to temperature and radiation. Naturally, if the terminal block is located in a very adverse environment, the condition of the terminal block should be evaluated. With respect to the connection, properly crimped lugs and properly torqued screws should result in long-serving connections. Care should be taken when PVC-insulated or PVC- or neoprene-jacketed wires are terminated in closed housings exposed to elevated temperature. Both PVC and neoprene will generate chlorine that can corrode exposed conductor and terminal lugs. In older PVCs, plasticizer may weep from the insulation or jacket and directly affect the connection. In either

PVC or neoprene that is highly aged, chlorine may be deposited on adjacent connections, causing at a minimum surface corrosion. When such conditions are identified, the need for corrective action should be reviewed. Some equipment manufacturers have also used PVC shrink sleeves (splices) in the wiring, and degradation of the sleeves has resulted in shorting between wires.

Properly made splices and terminations should not experience overheating. However, when terminations or splices are disassembled and reassembled or first installed, human performance errors or design deficiencies may occur that result in high-resistance connections, especially when connections involving aluminum conductor are being made. Accordingly, for non-intermittent, heavily loaded circuits, terminations and splices should be checked for elevated temperature conditions when operating at load after installation. This verification should be performed at some reasonable period following installation (one or two operating cycles). Identification of high-resistance connections may be through the use of infrared thermography or periodic visual inspection for signs of discoloration or deterioration of the splice or termination. If the adequacy of the connection was confirmed at the time of splice/termination preparation through the use of a micro-ohmmeter or other recognized method, periodic evaluation may be unnecessary for most connections, but it may be desirable for aluminum connections until stability is confirmed.

The cable aging management program may take credit for the performance of periodic infrared thermography or inspection of terminations and splices that is covered by the station maintenance program. The EPRI *Preventive Maintenance Basis Database* provides frequencies for performing routine infrared surveys or inspections of terminations [17]. Frequencies vary based on the end load’s component classification. Infrared thermography surveys should be scheduled to be performed when the equipment is energized and loaded to provide meaningful results.

Infrared thermography should also be scheduled as post-maintenance verification whenever terminations are disturbed for maintenance. This check should be done at least one hour after the equipment has been energized and loaded (to allow thermal stabilization) or at the earliest opportunity thereafter.

In many cases, access to terminations of low-voltage cable terminations (480 V or greater) may be limited due to equipment design or arc flash concerns. Generally, access to low-voltage power cables and their terminations can be performed by donning flash protection personal protective equipment and establishing an arc flash zone in accordance with National Fire Protection Association standards [18].

5
ACTIONS FOR DRY CABLES HAVING ADVERSE ENVIRONMENTS

Program Element 5

The low voltage power, control, and instrument cable aging management program should include one or more methods of determining whether significant aging of the cable is occurring for cables located in dry adverse environments. Physiochemical techniques that may be used include visual/tactile inspection, indenter modulus testing, near-infrared spectroscopy, and acoustic velocity assessment. Frequency domain reflectometry analysis may be used to electrically assess cable for thermal and physical damage. If removal of samples is possible, numerous laboratory tests are available. The assessment technique should be applicable to the polymer under assessment.

The effects of adverse dry environment conditions will be different from those caused by cables being energized in wet/submerged conditions because the failure mechanisms are not the same. Accordingly, different test and inspection methods will apply. This section addresses those tests that may be applied to cables in dry adverse environments.

Visual and Physical Identification of Thermal and Radiation Aging

As described previously, most adverse environments for low voltage power, control, and instrument cables are expected to be identified through plant walkdowns or opportunistic cable inspections during routine maintenance activities. Accordingly, the evaluation of the condition is likely to start as an external examination of a group of cables in a tray, a conduit, a motor control center, a motor operated valve operator, etc. that are exposed to the adverse condition. Once an adverse environmental condition is identified (for example, a location having elevated temperature, or a hot process pipe or component having missing or inadequate thermal insulation) and a tray or conduit containing power, control or instrument cable is in close proximity (less than a few feet [less than a meter] away), an assessment of the cable should be performed. For cables in a tray, the assessment should start with a visual/tactile assessment looking for indications of discoloration or cracking of the jacket and loss of flexibility. If the cables remain flexible and the surface condition remains the same as that of an unaged cable, no significant thermal aging has occurred. If the cable jacket has discolored, cracked, or stiffened, further assessment is necessary. When tactile assessment is used and a stiffened cable is identified, it is not necessary or recommended to bend the cable until it cracks. Determining that the cable resists bending provides sufficient indication that significant aging has occurred to the jacket or insulation.

With respect to thermal damage, the aging of the EPR, XLPE, and silicone rubber insulation systems does not cause them to be conductive. Rather, they retain their insulation resistance until they crack. Once cracked, the insulation resistance is likely to remain high as long as the crack remains dry and clean. However, bridging of the circuit may occur from conductor to conductor or from conductor to ground once condensing moisture or other conductive agent comes in contact with the crack. If the deterioration were allowed to go to the point where the insulation powdered, failure under completely dry conditions could occur if the conductors were to touch each other due to vibration or mechanical force acting on the cable. An extreme case of deterioration is severely aged PVC insulation which can produce acidic by-products that can flow into the terminations and cause shorting.

However, in many cases, the insulation could be essentially failed and circuits would continue to function.

Electrical assessment with commonly available techniques will generally be of little use in detecting the onset of aging and may not detect deterioration under dry conditions even if the insulation is cracked. Low-voltage power, control, and instrument cable can be evaluated by physical and chemical techniques. These techniques are most useful for identifying and trending aging. These include in-plant methodologies, such as visual/tactile assessment, indenter modulus, and acoustic velocity assessment; and numerous laboratory tests, including elongation-at-break, oxidation induction time and temperature, density change, and nuclear magnetic resonance shift. One electrical testing technique that may be used on multi-conductor cable is frequency domain reflectometry. This technique may be used to identify and locate thermal aging along the length of a cable. Although frequency domain reflectometry continues to be developed, research indicates that it readily identifies thermal damage [20]. Frequency domain reflectometry can identify subtle changes in capacitance of the insulation system through evaluation of reflected impedance resonance points. The various tests are described further below. Tables 5-1 and 5-2 contain a description of the expected effects of thermal and radiation aging for various cable polymers and possible evaluation techniques.

Cable connectors, splices, and terminations that are identified as being in adverse thermal or radiation locations should be visually inspected for deterioration. In general, terminal blocks are designed to withstand elevated temperature or radiation conditions; however, visual inspection can identify corrosion of connections or cracking or crazing[10] of the insulator, indicating a need for replacement or repair. Visual inspection of splices may indicate unraveling or deterioration of taped splices or deterioration of a heat-shrink splice or the interface between the splice and cable surface. Visual inspection of a connector can identify deterioration of seals or the back shell connection to the cable.

[10] Crazing is a pattern of fine surface cracks on an insulator that could lead to tracking between connections.

Table 5-1
Effects of Thermal/Radiation Aging on Low Voltage Power, Control, and Instrument Cable Jackets

Material	Temperature-Induced Degradation	Radiation-Induced Degradation	Condition Evaluation	Effect of Degradation
Neoprene	Hardening with spontaneous cracking and discoloration (turning greenish brown) (see note 1)	Hardening	Visual inspection can identify discoloration or cracking. Hardening can be manually or indenter evaluated.	Cracking exposes insulation to airborne moisture, causing limited effects on insulation. Failure of neoprene jackets on shielded cable may allow additional grounds, causing circuit noise to increase. Severe aging will cause chlorine to be released, possibly leading to corrosion of surrounding metals.
CSPE (Hypalon)	Hardening with discoloration (turning greenish brown)	Hardening	Visual inspection can identify discoloration. Hardening can be manually or indenter evaluated.	Until extreme hardening occurs, Hypalon or CSPE will remain intact. However, if a through fault occurs on a power cable, the jacket may crack due to motion from high magnetic fields.
PVC	Hardening, possible spontaneous cracking, weeping of plasticizer; darkening with age (see note 1)	Production of hydrogen chloride (HCl)	Hardening may be observed manually or through indenter. HCl production may be indicated by white powdering or corrosion of surrounding metal. Plasticizer may cause the surface of cable to be tacky or may weep from surface.	Cracking exposes the underlying insulation to more direct exposure to the stressor. HCl production could corrode surrounding metal components, as could weeping plasticizer.
Chlorinated Polyethylene (CPE)	Hardening, cracking, discoloration (turning greenish brown) (thermoplastic version only)	Hardening, cracking	Hardening may be observed manually or through indenter.	Material will be sensitive to manipulation. Some chlorine may be generated that could affect surrounding metals (generally associated with thermoplastic). Cracking of jackets on shielded cables may lead to additional shield grounds, possibly causing increased noise on the associated circuit.

Notes: 1. *Spontaneous cracking* means that the material shrinks when significantly aged and cracks occur even though the cable has not been manipulated or physically disturbed.

Table 5-1 (continued)
Effects of Thermal/Radiation Aging on Low Voltage Power, Control, and Instrument Cable Jackets

Material	Temperature-Induced Degradation	Radiation-Induced Degradation	Condition Evaluation (See note 1)	Effect of Degradation
Cross-Linked Polyethylene (XLPE)	Hardening	Hardening	Line resonance analysis (LIRA) may be used to determine whether significant aging has occurred. Jacket is generally a leading indicator.	Ultimately, the insulation could crack. Depending on the severity of the temperature (<100°C), the life still could be long (decades), provided condition is corrected before severe degradation occurs.
Butyl Rubber	Hardening or softening	Softening	Jacket is generally a leading indicator.	Softening may occur on advanced thermal aging. May also soften under irradiation.
Fire-Retardant Ethylene Propylene Rubber	Hardening	Hardening	LIRA may be used to determine whether significant aging has occurred. Jacket is a leading indicator.	Extreme thermal aging can cause physical failure (embrittlement and cracking). Material will be susceptible to failure under manipulation and possibly under loss-of-coolant accident (LOCA) conditions.
Ethylene Propylene Rubber with Bonded Chlorosulfonated Polyethylene (EPR/CSPE bonded) (see note 2)	Initially hardening of the CSPE layer, followed by hardening of the EPR layer. CSPE will discolor (turn greenish brown) with exposure to elevated temperature	Same as temperature	LIRA may be used to determine whether significant aging has occurred. Jacket is a leading indicator. Indenter or acoustic assessment may be used to evaluate hardening.	Hypalon or layer will become controlling when highly aged. Through cracking of CSPE and EPR may occur if manipulated or exposed to a high pressure LOCA environment, although this effect will be less important for large conductor sizes (6 to 8 AWG and larger) where material thicknesses are larger.
Ethylene Propylene Rubber/Neoprene (see note 3)	Early hardening and cracking of neoprene layer; eventual hardening of EPR layer	Same as temperature	LIRA may be used to determine whether significant aging has occurred. Jacket is a leading indicator. Indenter or acoustic assessment may be used to evaluate hardening.	Neoprene will spontaneously crack, but does not seem to cause through cracking of EPR. However, the hardened neoprene could cut the insulation if the cable were manipulated (bent).

Table 5-1 (continued)
Effects of Thermal/Radiation Aging on Low Voltage Power, Control, and Instrument Cable Jackets

Material	Temperature-Induced Degradation	Radiation-Induced Degradation	Condition Evaluation (See note 1)	Effect of Degradation
Chlorosulfonated Polyethylene (CSPE) (see note 4)	Hardening of CSPE insulation; CSPE will discolor (turn greenish brown) with exposure to elevated temperature	Same as temperature	LIRA may be used to determine whether significant aging has occurred. Outer CSPE jacket would age simultaneously from external environments but indenter or acoustic assessment may be used to evaluate hardening.	Hardened CSPE may crack if manipulated or exposed to a high-pressure LOCA environment.
Silicone Rubber	Little effect unless temperatures are extreme, then hardening	Loss of tensile properties	Generally difficult to assess due to glass or asbestos braid coverings.	Loss of tensile properties would make insulation susceptible to manipulation and pressurized steam exposures.

Notes:

1. In most cases, cable jackets will be leading indicators of thermal/radiation damage in that jackets generally have ratings that are 59°F (15°C) lower than the insulation. The exceptions are jackets on silicone rubber cables that are constructed of glass or asbestos braids that do not provide indication of thermal/radiation damage. Composite EPR/CSPE and EPR/neoprene insulated wires are also exceptions; with either type, insulation and jacket essentially age at the same rate.

2. EPR/CSPE is a composite insulation having EPR as the primary insulation with a layer of CSPE applied over the EPR to add fire retardancy. The CSPE layer may or may not be bonded to the EPR.

3. EPR/neoprene is a composite insulation having EPR as the primary insulation with a layer of neoprene applied over the EPR to add fire retardancy. The neoprene may or may not be bonded to the EPR.

4. CSPE was used as an insulation by a limited number of manufacturers. Boston Insulated Wire's Bostrad 7 had CSPE insulation; Bostrad 7E had EPR insulation with a bonded CSPE insulation jacket.

Oil and Chemical Exposure

Identification of oil or chemical exposure will likely occur during maintenance on a device in the vicinity of cables, from operator inspections, or in response to a spill event. Once the chemical, oil, or hydraulic fluid is removed from the surface of the cable, visual/tactile inspection is the first step in determining if significant deterioration has occurred. Swelling or softening of the exposed jacket or insulation is an indication of adverse effects. If once cleaned, there is no immediate effect of the exposure, re-inspection after a reasonable period (6 months to a year) is appropriate to determine if an adverse interaction has occurred. If swelling or softening has occurred, replacement or repair would be appropriate.

Visual/Tactile Assessment

Visual/tactile assessment is a key tool in the initial assessment of low voltage power, control and instrument cable aging, because the aging is environmentally induced.

Control and instrument cables have low conductor currents and do not experience ohmic heating. Most cables have jackets that have lower temperature ratings than the insulation. The jackets of these cables will age and harden more readily than the insulation. In cases where the aging is caused by the external environment, the jacket will generally age faster than the insulation. If the aging is caused by ohmic heating (low voltage power cables), the jacket will still tend to age more rapidly than the insulation, but it may not lead the aging of the insulation by a significant factor. Care should be taken in those cases in which the insulation and jacket material are the same material (for example, cables with both the jacket and the insulation made of CSPE or both made of XLPE), since the aging of the insulation and jacket will proceed at the same rate. In such a case the assessor needs to be more conservative in evaluating the condition of the cable.

The aging of the jacket will cause the cable to stiffen and lose flexibility. A visual/tactile assessment can identify the unaged condition by evaluating cable samples from the warehouse or cables located in benign environments. Most of the rubber jackets can also turn brownish green when exposed to severe thermal conditions. If the color remains like an unaged cable and the cable retains flexibility, then significant thermal aging has not occurred. If the cable is stiffening, further assessment is necessary, with severe hardening requiring more immediate attention. The EPRI report *Training Aids for Visual/Tactile Inspection of Electrical Cables for Detection of Aging* (1001391) [20] describes how visual/tactile training aids were developed and what can be deduced from visual/tactile inspection. Additionally, EPRI report 1022979 [21] is a computer based training aid for persons tasked with performing cable walkdowns and visual/tactile inspection. If visual/tactile assessment identifies aging of the cable, the cable may be repaired or replaced, or a more sophisticated assessment technique, such as the indenter or one of the other nondestructive test methods described in the following sections, may be applied. Alternately, a sample could be removed for laboratory assessment.

Visual/tactile assessment may be used to evaluate the condition of cables in trays that are adjacent to heat sources or may be used to assess the condition of cables in the vicinity of the end devices (for example, limit switches and solenoid-operated valves), where high temperatures may occur. The technique may be incorporated into specific area inspections or inspections done during routine maintenance of components connected to cables.

Indenter Modulus Testing

Indenter modulus testing uses a nondestructive, in-plant test device that measures *compressive modulus*, an indication of hardness, of a cable jacket or insulation [22]. A small probe is pressed against the cable jacket or insulation at a constant velocity while the force is measured. The probe is retracted when a force limit is reached. The change in force is divided by the change in position during the compression to arrive at the modulus. Correlations between the indenter results and elongation at break are available for a number of materials. See the EPRI products *Cable Polymer Aging Database* (1011874) and *Initial Acceptance Criteria Concepts and Data for Assessing Longevity of Low-Voltage Cable Insulations and Jackets* (1008211) [23, 24]. Although tactile testing provides a rough indication of the degree of aging, the indenter provides a more precise indication of the degree of aging. The indenter may be applied to cable insulation or jacket wherever >4 in. (>10 cm) of cable length is exposed.

Ultrasonic Velocity Assessment

As polymers in cable insulation harden or soften with aging, the velocity of ultrasonic waves through them changes. The change in ultrasonic velocity can be correlated with the change in elongation at break of the insulation or jacket of a cable and used for assessment of aging of the material. The test is nondestructive, and a portable test device has been developed [25]. Ultrasonic testing has been demonstrated in nuclear plant applications, but it remains under development.

Frequency Domain Reflectometry

Frequency domain reflectometry (FDR) tests uses the cable under test to modulate a high-frequency white noise, low-energy electrical signal. FDR provides a tool for determining the distance to fault in cable systems. The process sends a signal into the cable and analyzes the complex reflected wave to determine the distance to various sources of reflection (opens, shorts, splitters, etc.). The reflected resonances indicate the points of termination and any significant impedance changes along the length. Thermally damaged segments of the cable are indicated by such resonances. The test provides a relative severity of the damage and the location. The test is performed by sending a signal down one conductor of a multi-conductor cable and using an adjacent conductor (or shield) as the signal return path. The test conditions may require one end of the circuit to be de-terminated. The opposite end may be either open or closed. EPRI report 1015209 describes the technique and its application [19]. Frequency domain reflectometry testing is useful to determine if cables within a conduit or that are physically difficult to gain access to have been damaged by adjacent thermal sources. Frequency domain reflectometry has been demonstrated in research and through limited in-plant use. It continues to be developed.

Near-Infrared Spectroscopy

For cable polymers that are not loaded with carbon black (that is, cables with lighter colors such as red, orange, or white), near-infrared spectroscopy may be used to nondestructively identify the chemical composition of cable insulations found on low voltage power, control, and instrument cables and to assess the aging of the materials. The technique measures the absorption of incident light by chemical groups in the polymer, providing a unique fingerprint for each cable insulation compound and its state of aging. Spectra collected by a portable spectrometer from field cables can be compared with results for insulation formulations contained in a near-infrared spectroscopy library for which thermal and radiation aging characteristics have been established [26].

Laboratory Tests

Numerous laboratory tests that assess the degree of aging of cable polymers are available. A number of tests have been developed that only require samples on the order of 10 mg or less. With such tests, a small sample of jacket or insulation may be removed and a repair made so that the cable can remain in service while the assessment is being made. Descriptions of such techniques are provided in the EPRI report *Cable Polymer Aging and Condition Monitoring Research at Sandia National Laboratory Under the Nuclear Energy Plant Optimization (NEPO) Program* (1011873) [14].

If larger sections of cable (1.5 ft. [≈0.5 m] or more) can be removed, numerous traditional physical and chemical tests—including elongation-at-break, swell-gel, density, and others[11]—may be applied to cable insulation and jacketing to evaluate the degree of aging.

Remaining Life Evaluation

EPRI research provides a methodology to evaluate cable condition and remaining life. This method is provided in EPRI 1008211 [24]. In many cases data exist that relate cable thermal aging to remaining absolute elongation at break. Manufacturers may also have provided values of elongation at break for their cables in their test reports. If that data is not available, an approximate estimation of new condition can be obtained by using a sample of the cable in question from storeroom stock or a mild plant environment as representative of a "new" cable. Additionally, EPRI CPAD [23] contains test data for many cable and insulation types from new to end of life obtained from laboratory accelerated aging studies. If a cable current condition and "new" conditions are known, then the report [24] shows how to use those values to establish the change from new to now. Then by using the time from installation to the time at which the current condition has been established one can solve for the time to the chosen "end of useful life". This is often described as the 50% elongation at break point[12].

[11] See The Electrical Cable Test Applicability Matrix, EPRI report 1021629[27] for a complete description of these test and how to apply them to evaluate cable condition.

[12] The end of useful life cannot be universally established as 50% elongation at break. Some polymers may age rapidly to end of life well before 50% elongation at break (often described as a cliff edge). A polymer that has been shown through accelerated thermal aging studies to behave in such a way should have an end of life value established conservatively to avoid setting the value at or beyond the "cliff edge".

Traditional Troubleshooting Techniques

Thermal and radiation aging of cable polymers does not cause electrical indications of degradation that are observable by traditional means, such as insulation resistance or time-domain reflectometry (TDR), until the insulation system has failed. Thermal aging, in many cases, will improve insulation resistance by drying out the insulation. Insulation resistance will degrade only after the insulation fails by cracking or powdering and moisture enters. Insulation resistance tests and time-domain reflectometry are not useful for trending the aging of dry cables. However, these tests are useful troubleshooting tools when a failure has occurred.

For a further description of these and other tests like elongation at break, oxidation induction time, and others refer to EPRI's Cable Test Applicability report 1022969 [27]. The appendix of that document provides a description of each test method, what the results provide and which jacket and insulation materials can be evaluated for aging using that technique.

6
ACTIONS FOR LOW VOLTAGE POWER, CONTROL, AND INSTRUMENT CABLES IN WET ENVIRONMENTS

Program Element 6

Low voltage power, control, and instrument cables subject to wet conditions and having a known or suspected water-related degradation mechanism should be periodically tested on a sampling basis via insulation resistance to ground and, as practicable, conductor-to-conductor or other recognized tests to determine whether degradation has occurred. Results should be trended. Acceptance criteria and/or action levels should be developed. For instrument circuits where limited noise is allowable and plant experience has identified that wetting of the cable affects the noise, action should be taken to dry the cable, or periodic testing should be performed to confirm that the noise is within acceptable limits.

To the extent practicable, manholes, vaults, and ducts should be drained, so that cables are not in or covered by long-standing water.

As described in Section 4, only a few instrumentation and control cable insulation types have exhibited water-related degradation. ICEA manufacturing standards require insulation stability testing to be performed by manufacturers to prove stability of cable insulation under wet conditions, so that no significant deterioration should occur for an extended period unless the conditions of the soil or water are particularly aggressive. Plant and industry operating experience is important for determining if water-related deterioration of instrumentation and control cable is occurring. If a cable fails under wet conditions, removal and determination of the cause are recommended. Sharing of the results is also recommended because forensic information for instrumentation and control cables, as with all low-voltage cables, is rare. EPRI research [15] results for four of the most commonly used low voltage insulation types showed that they were not susceptible to wet aging degradation.

In low-voltage cables, the thickness of insulation and jacketing that are used is driven by mechanical protection capabilities rather than by voltage induced dielectric stress. Therefore, the voltage stress in the insulation is quite low by comparison to that of medium-voltage cable, and no electrically driven failure mechanism such as water treeing has been shown or is expected to occur. Failures have occurred for specific insulation types discussed in Section 4, possibly due to long-term chemical deterioration of jackets and insulations, but failures are more often due to installation or post-installation damage as described in EPRI report 3002010637 [28].

The number of failures of low voltage power, control, and instrument cables under wet conditions from all causes is low in comparison to the number of circuits in service, indicating that a low failure rate and a long mean time between failures exist. Accordingly, if a concern arises that water-related aging is affecting a specific type of insulation, insulation resistance testing of a sample of the wet circuits may be used. If the sample shows no degradation, confidence will be gained that the problem is not widespread. Conversely, if some of the sample identifies degradation, the sample population should be increased to determine the significance of the problem and to guide corrective action.

If present, deterioration of low voltage power, control, and instrument cable insulation from wetting can be detected through trending of insulation resistance. Often, dc systems have a continuous ground detector circuit that would also indicate whether the insulation failure on a leg of a control circuit has occurred. Such grounds should be eliminated to preclude a pole-to-pole short should a ground occur on the opposite pole. Some ac systems may also have continuous ground detection to detect high-resistance grounds. Grounds on the ac system, when alarmed, should be identified and isolated before the insulation has completely failed.

In some cases, time-domain reflectometry (TDR) may identify wetted sections of instrument and control cables; however, TDR will generally not be useful in establishing whether degradation of the insulation has occurred.

Low voltage power and control cables' jacket deterioration by wetting will have little effect on the function of the cable. Deterioration of the insulation must occur for failure to occur. However, instrumentation cables, whether twisted shielded pairs, coaxial cables, or triaxial cables, are shielded with the shields grounded at one end of the circuit to reduce induced and radio noise. Jacket degradation, whether from long-term aging or physical damage, may allow multiple grounds to occur on the shield under wet conditions. Multiple grounds on the shield could result in excessive noise on the associated circuit. If a plant is not experiencing adverse noise conditions on wet circuits, then it is likely that no problem exists. However, if the plant does experience noise on wet circuits, the concern may be addressed in three ways:

- Maintain dry conditions in the duct, vault, and manhole system
- Periodically assess circuit noise and verify that the noise remains below acceptable levels
- Periodically perform insulation resistance testing of the cable jacket between shield and ground

If the noise is unacceptable or the insulation resistance of the jacket is too low, and removal of water is not possible or not effective in reducing the noise, replacement of the cable will be necessary.

For motor circuits, the insulation resistance to ground may be measured with the motor connected. Insulation resistance results will be affected by temperature and humidity, especially of the end device (for example, a motor). Accordingly, to the extent possible, the results should be compensated for the conditions at the time of the test.

Pumping of Manholes and Ducts

Removing water from around the cable will not reverse water-related degradation if any has occurred. However, removing water will remove the source of and transfer mechanism for ions that may lead to degradation. Instituting a pumping program, installing automatic sump pumps, or repairing failed automatic pumping systems is recommended.

It is recognized that not all systems can be pumped dry. Continued operation of cables under wetted conditions is allowable, but condition of the cable insulation should be evaluated through periodic assessment.

Rain and drain conditions will not adversely affect jacketed cables. Water migration into the jacket can take between a number of months to years. Low voltage power, control, and instrument cables are not susceptible to water treeing because the voltage stresses are too low to induce the electrochemical/ electromechanical degradation mechanisms involved. Other water-related degradation mechanisms may exist; however, manufacturers' water stability tests indicate that water-related degradation should not occur.

Relative Importance of Low-Voltage Power Systems

For most plants, safety-related emergency power is generated at 4 kV or greater. For plants having safety-related power systems that operate at 4 kV or greater, the low-voltage power circuits have a lesser safety significance.[13] However, a few plants have safety-related emergency power generated and distributed at low voltage (such as 480 V). For this set of plants, assessment of low-voltage power cables, especially those that are wetted, is more important to verify that significant insulation deterioration has not occurred, and greater scrutiny of wetted circuits is desirable. In setting up the low-voltage power cable aging management program, the safety significance of the cable circuit, coupled with the severity of the adverse environment/service condition, may be used to determine those cable circuits that should receive the most attention and those that have little impact and/or no adverse conditions.

Continuously energized wetted (and potentially wetted) dc power distribution circuits supporting Maintenance Rule applications should be included in assessments. An instance of insulation polymer instability from long-term wetting has occurred in one dc application and is suspected, but not yet proven, in another. The known failure was associated with extremely aggressive chemical conditions and elevated underground temperature. It is not clear whether the observed degradation was due to the insulation polymers composition and/or the specific operating conditions. Vigilance is recommended until more forensic data are available to make firm conclusions.

Test Methods

Although a number of tests are available for troubleshooting low voltage power, control and instrument cable insulation problems, insulation resistance remains the main method for assessing degradation of wet cable circuits. Capacitance tests may indicate that a cable has absorbed water, and time-domain reflectometry may identify the location of a wetted portion of the cable. However, individual tests do not indicate whether degradation has occurred.

Low insulation resistance or a decreasing trend in insulation resistance is indicative of insulation degradation for low-voltage circuits. Insulation measurements are affected by temperature and moisture conditions at the time of test. Care must be taken when making comparisons between tests performed at different times. Changes could be the result of different temperature or

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There may be some low-voltage power loads that do have a significant effect on power production, such as service and instrument air, stator water cooling, electro-hydraulic control, and so on.

moisture conditions during the tests. Large decreases in insulation resistance that are not from conditions at the time of the test are important, and a continuing decreasing trend of a large magnitude (e.g., multiple decades of resistance) should be investigated further. Although the use of an absolute limit for low insulation resistance provides a cutoff for continued use of a cable, or at a minimum indicates the need for further assessment, trending of insulation results will provide more information regarding the rate of change and an earlier indication that deterioration may be occurring.

Acceptance Criteria Development

Minimum insulation resistance values for return to service exists for cable circuits. These values are not meant to indicate that the cable insulations are in "good" condition if they just exceed these values; rather, they indicate that low-voltage circuits can function. **These minimum values of insulation resistance should not be used as acceptance criteria.** EPRI report EL-5036 [5] provides the following equation for a field acceptance limit[14] for cable:

$$IR_{\min} = 1000 \times \left(\frac{kV + 1}{L} \right) \quad M\Omega$$

Where:

kV is the insulated rated voltage, in kilovolts.

L is the cable length, in feet.

For comparison, cable manufacturing standards, such as the ICEA publication *Ethylene-Propylene-Rubber-Insulated Wire and Cable for the Transmission and Distribution of Electrical Energy* (S-68-516), require minimum insulation resistances for new cable based on the following equation [30]:

$$IR = 10{,}000 \log_{10} (D/d) \text{ M}\Omega\text{-1000 ft.}$$

Where:

D is the diameter over the insulation.

d is the diameter under the insulation.

The SI version of this acceptance criterion is:

$$IR = 3050 \log_{10} (D/d) \text{ M}\Omega\text{-km}$$

To allow a comparison of the new cable requirement to the minimum acceptance criteria, assume a 200-ft (0.061-km) long XLPE-insulated cable with a 14-AWG (2.08 mm^2) conductor and a 30-mil (0.76-mm) thick 600-V rated insulation. A representative cable of this type would have a 0.14-in. (3.5-mm) diameter over the insulation (D) and a 0.08-in (2.03 mm) diameter under the insulation (d). The field acceptance limit would be 8 MΩ. The new cable value would equal the following:

$$IR = 10{,}000 \log_{10} (0.14 \text{ in}/0.08 \text{ in}) \text{ M}\Omega * 1000 \text{ ft.}/200 = 12{,}151 \text{ M}\Omega$$

[14] This limit is only recommended for application to low-voltage cable for condition assessment. More sophisticated test methods and acceptance criteria are recommended for assessing medium-voltage cable.

If the circuit was 2000 ft. (610 m) long, the new cable value would be 860 MΩ. The length of the circuit is a significant consideration related to expected insulation resistance values.

A newly installed cable should have a near-factory-value insulation resistance per 1000 ft. (305 m). When evaluating insulation resistance results from cable testing, trending of results allows identification of deterioration. Some variations in results are natural due to difference in temperature and humidity at the time of test. However, a continuing decrease on the order of two decades is a strong indication of significant degradation. If no trend data exist, caution should be used if a value of less than 10 times the minimum field acceptance criteria is found. The period between tests should be reduced, or an assessment should be made to identify the cause of the low insulation resistance. Although leakage currents in control and instrumentation circuits may be low, significant circuit degradation has likely occurred when insulation resistance is below 100 MΩ-1000 ft.

If power cables are connected to motors at the time of insulation resistance testing, then the minimum acceptance criterion for motor insulation should be considered. The EPRI report *Power Plant Electrical Reference Series: Volume 6, Motors* [31]) provides a formula for a minimum value for a motor:

$$IR_{min} = ((\text{Rating in kV}) + 1)\ \text{M}\Omega$$

The value of insulation resistance should be corrected to 104°F (40°C) to allow trending and comparison. The EPRI report [31] states that this value does not provide a basis for considering a motor's insulation as good or to expect a long life when a motor's insulation resistance approaches this value. It also states that good motor insulation will normally read 200 MΩ to infinity.

IEEE Std. 43-2000 [32] states that the (rating in kV + 1) MΩ value applies to pre-1970 winding types and 100 MΩ is applicable to more modern form wound systems. Although many plants transfer the limits for rotary equipment to cable, the 100 MΩ per 1000' (30.4 MΩ per kilometer) limit is more applicable to cable than the (rating in kV + 1) MΩ limit, and the length of the cable should also be considered.

High-Range and Wide-Range Radiation Monitor Circuits

There are two concerns for radiation monitoring circuits: maintaining adequate insulation resistance and maintaining circuit continuity.

Insulation Resistance for Radiation Monitors

The specifications for high-range radiation monitors have requirements for high insulation resistance values in excess of gigohms to ensure function. The acceptance criteria for such circuits should be based on the minimum requirements to ensure system function. New coaxial cables have insulation resistances on the order of 15 to 40 gigohms-1000 ft. (4.5 to 10.4 gigohms-km).

Two approaches may be taken to verifying that the circuit insulation resistance remains acceptable. If the circuit for periodic calibration of the system contains the cable, then as long as the system can be acceptably calibrated, the insulation resistance can be assumed to be acceptable. If not, then periodic insulation resistance tests are necessary. These approaches are acceptable in accordance with Section XI.E2 of Volume 2 of the *Generic Aging Lessons Learned (GALL) Report* [9].

Circuit Continuity

Some plants have had problems with circuit continuity related to connectors in the system. Periodic cleaning of the contact controls this problem. Another possible issue is an assembly problem for certain reverse configuration Amphenol connectors that was recognized during an EPRI research project. The EPRI report *Evaluation of Moisture Intrusion in Coaxial Connectors* (1001390) identified that even with careful preparation an assembly error was possible [33]. The center pin for the connectors was held in place by the placement of the cable end in the connector. If the cable end backed out during the preparation of the connector, the center pin could be up to 1/8 in (3 mm) from being completely inserted. Evaluation of the connectors by longitudinal sectioning after the test program indicated that when the back shell seal nut was tightened, the compression of the grommet could cause the cable to be forced out of the connector by pushing back on the jacket end. Figure 6-1 shows the nature of the problem. Under this condition, the male center pin would be just in contact with the female portion of the connector rather than fully mated.

To preclude this problem, following completion of tightening of the back shell nut, the center pin should be verified as being fully seated and should be pressed upon to ensure that it does not retract significantly under load. If the position is correct and the pin does not significantly retract, the grommet did not push the cable back and the assembly of the half connector with the male center pin was correct.

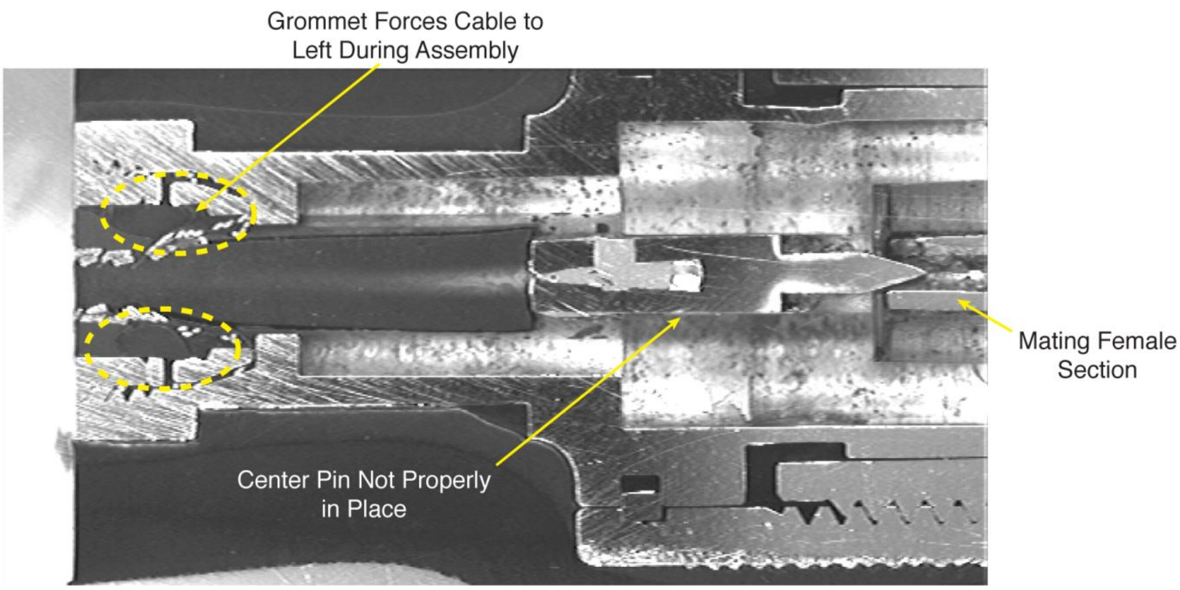

Figure 6-1
Sectioned Amphenol Connector Showing Mating Problem During Assembly due to Grommet Forcing Cable Out of Connector

7
ACTIONS FOR FAILED OR DETERIORATED CABLE

Program Element 7

The low voltage power, control and instrument cable aging management program should require that appropriate corrective action be taken if significant aging of cable insulation or conductor systems is identified or suspected due to adverse localized environments. Those actions may include assessment, testing, repair, or replacement, as appropriate. If the investigation of the failure or deterioration indicates a generic degradation mechanism, circuits with similar conditions should be reviewed to determine if they, too, need corrective action.

Operability Concerns

Depending on the severity of the degradation identified, an operability concern may or may not exist. Severe physical degradation, such as cracked insulation, damaged conductors, or extreme hardening or softening of insulation, or a “highly degraded” result from electrical testing, indicates an operability concern.

Severe degradation from normal operation should not occur for cable in circuits that require environmental qualification in accordance with 10 CFR 50.49. If these cables are found to be severely degraded or degraded beyond the degree expected for the given period of service, an assessment is necessary to determine whether the environment is more severe than that used in the qualified life calculation or whether the material is experiencing unanticipated aging that is not consistent with the environmental qualification. Adjustment of the qualified lives of the cable and like cables in similar environments may be necessary.

If safety-related cables located in mild environments (cables that will not experience accident environments for which they must remain functional) are found to be degraded severely from normal environments, the cause must be determined and appropriate corrective action taken. Normal environments that could adversely affect cable in mild environments include elevated ambient temperature; chemical, oil, or hydraulic fluid exposure; or long-term submergence in water. For the most part, the elevated radiation doses that would adversely affect cable insulations and jackets are not expected to exist in mild environment zones.

Lesser indications of degradation would constitute a need for further vigilance but not an immediate operability concern. Examples of these types of degradation include a limited stiffening of insulation and jacket or an electrical test result indicating “aged” insulation (for example, low insulation resistance but not less than minimum acceptable insulation resistance). The following subsections provide insights on verifying the condition and determining course of further action.

Corrective Actions

The corrective actions to be taken in response to cable degradation will depend on the nature of degradation and whether the degradation is localized or distributed over a significant length of the cable. Actions may be permanent or temporary, depending on the nature of the application and the licensing basis. The following text provides some possible considerations and resolutions. These considerations and resolutions are not all-inclusive. Plant-specific requirements and application-specific conditions may dictate different resolution paths.

Insulation Resistance Test Indicates Degraded Insulation on Wet Cable

If the insulation resistance of the cable's insulation has dropped but is still adequate for service, shortening the time between insulation resistance tests and trending the result is recommended. If continued deterioration is identified and the cause cannot be identified, replacement of the cable should be considered. If the cable is replaced, removal of the old cable for forensic assessment is recommended. If the degradation was caused by physical damage (such as cuts or gouges), laboratory assessment is unnecessary. However, if there are no obvious indications of the cause of failure, laboratory assessment is recommended to determine whether polymer degradation has occurred. Information for removal of cable and recommended forensic inspections can be found in the cable harvesting guidance, EPRI report 3002002994 [30] or go to http://cableharvest.epri.com.

If unacceptable insulation resistance is identified, immediate replacement should be considered. Removal and forensic study is also recommended.

Multiple Grounds on Wet Service Coaxial Cable Shields

If excessive noise is recognized on coaxial circuits that run underground and the source of the condition is multiple grounds, a determination should be made as to whether these circuits are wet. If they are wet and draining of the water is possible, the runs should be dried. If the problem persists, replacement of the cable may be necessary. Replacement with an impervious design may be necessary to resolve the problem if maintaining dry conditions is not possible. If the cable being replaced can be removed, it should be evaluated to determine if physical damage to the cable jacket was the cause or if the water passed through the undamaged jacket.

Cables Experiencing Localized Thermal Damage

Two concerns exist for localized thermal damage. The first effect power cables and is the result of ohmic heating. In this case the temperature of the insulation is so high as to cause the insulation system to fail due to thermal avalanche. In such a case, the local volumetric insulation resistance would decrease, causing higher leakage current and further elevating the insulation temperature. Eventually, the leakage current and insulation temperature are so high that insulation breaks down. This is not an aging phenomenon but a direct effect of excessive temperature. In power cables, given the thickness of insulation and jackets by comparison to operating voltage, leakage currents should be small, and thermal runaway should be unlikely.

The aging concern is that the temperature resulting from ohmic heating for power cables is not high enough to cause thermal avalanche but is high enough to cause hardening of jackets and insulations (softening of sulfur-cured butyl rubber) over time. Eventually, cracking of the insulation could occur from manipulation or from motion induced by a fault current surge. For sulfur-cured butyl rubber, long-term thermal aging could cause softening that could allow compression of the insulation, leading to high electrical stress and failure. Thermal degradation of environmentally qualified cables located in harsh environment areas can cause the cable to have a shortened qualified life.

The second case is caused by high ambient temperature and this operating environment can be an aging concern for power, control, and instrument cables. In this case the source of heating is not conductor current; it is the environment. Conductive, convective, and radiant thermal energy can cause localized damage. For most cable insulations and jackets, the thermal energy will cause hardening of jackets and insulations over time. Eventually, cracking of the insulation could occur from manipulation or pressurized steam accidents. If the source of the thermal energy is not removed or the cable replaced, and aging is allowed to go to the extreme, the polymers will lose their tensile properties and will crack and/or powder. For sulfur-cured butyl rubber, long-term thermal aging could cause softening of the insulation. If the insulation does not have a second layer, such as PVC, shorting of conductors is possible when the insulation softens.

Thermal degradation of environmentally qualified cables located in harsh environment areas can cause the cable to have a shortened qualified life.

Evaluation of the Degree of Damage

Environmentally induced degradation will generally be caused by an adjacent heat source that was not properly controlled (such as adjacent process pipe with inadequate or missing thermal insulation). The first assessment should be of the jacket to determine whether complete hardening has occurred or if some elasticity remains. If some elasticity remains, the likelihood of damage to the cable insulation is low, and the thermal insulation on the process component should be improved. Periodic inspection of the cable is recommended to verify that deterioration is not worsening significantly with time.

Evaluation of the severity of the jacket degradation may be performed through indenter modulus assessment [22]. The use of indenter testing allows quantification and trending of the hardening of the jacket to provide insights as to the relative hardness and the degree of continued aging.

Frequency domain reflectometry may be used to determine whether an adverse localized thermal environment has affected the insulation [19]. If the effect was limited to the jacket on shielded cable, frequency domain reflectometry should identify no significant signal. If the insulation was affected, frequency domain reflectometry would give a relative indication of the severity of the effect. This technique may be used on multi-conductions cable by testing adjacent conductors. The results of this testing can provide only an indication of the relative degree of damage, not a precise indication of expended or remaining life.

Insulation resistance is not a useful indicator of thermal degradation in that the insulation resistance is likely to improve from heating under dry conditions as moisture is driven from the cable. Insulation resistance will indicate a problem only after the insulation has failed physically and moisture has entered through cracks. Insulation resistance is generally a lagging indicator of thermal damage to insulation and jacketing. Insulation resistance is generally only a useful indicator of degradation for cables in a wet environment.

Correction of the Adverse Localized Thermal Environment

When an adverse localized thermal environment is identified, the thermal insulation on the source of the heat and radiant energy should be replaced, repaired, or upgraded. If this activity does not sufficiently reduce the effects on the cable, consideration should be given to rerouting the cable. If the cable must remain where it is, periodic assessment of the condition of the cable should be implemented to verify that the rate and severity of the cable degradation are known, so that condition-based corrective action may be taken at the appropriate time.

Replacement of Thermally Damaged Cable

Consideration should be given to replacing cables that have been thermally damaged to the point at which they are no longer flexible. Alternately, a small sample of insulation can be removed and sent for laboratory tests to determine whether the degradation has proceeded to the point at which the insulation is susceptible to failure upon manipulation or under a steam accident (if applicable). Additional information on testing techniques of various polymers can be found in EPRI report 1022969 [28].

If severe thermal aging of the insulation is identified, removal and replacement of the affected cable section is recommended. If the qualified life of a cable is shortened due to the adverse localized thermal environment, it must be replaced before the end of its qualified life. Replacement of a section through the use of appropriate splices or replacement of the entire circuit is permissible.

High-Resistance Connections

This condition generally is only a concern for low voltage power cable due to the higher voltage and larger currents they carry compared to control and instrument cables. If inspection or infrared assessment of cable connections indicates significant heating of a connection (for example, for infrared thermography), the affected connection should be repaired or replaced. Early replacement is recommended to preclude significant damage to the cable insulation at the connection point. If the cable insulation has been damaged, repair or replacement of the cable or the affected section will be necessary, as well.

Cables Damaged by High Current

Damage to cable from ohmic heating due to high currents is likely to affect the entire length of the cable, with the worst effect in sections having elevated ambient temperature. The entire circuit generally will require replacement. Rectifying the cause of the high current is necessary, whether it is from lack of transpositions in multi-conductor per phase circuits or undersized conductors.

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A
THERMAL AGING OF NEOPRENE AND CHLOROSULFONATED POLYETHYLENE

The jackets for instrumentation and control cables do not have as high a temperature rating as the insulation system and generally age more rapidly than the underlying insulation, given the same temperature. The two most common jackets in use are neoprene and chlorosulfonated polyethylene (CSPE, commonly referred to by the DuPont brand name Hypalon). Because they typically age faster than the underlying ethylene propylene rubber and cross-linked polyethylene insulations, they will be leading indicators of thermal degradation. Figures A-1 and A-2 provide temperatures at which common neoprene and CSPE jackets will reach 50% remaining absolute elongation. The figures show that the more modern CSPE material ages more slowly than the older neoprene. These figures do not represent an end of life for the cables but rather conditions at which aging can begin to be detectable; they provide an indication of the temperatures at which a boundary for adverse conditions can be set, depending on the age of the plant and the type of cables that are installed. The concept of using a jacket as a leading indicator of thermal/radiation degradation is that if the jacket remains flexible and resilient and shows no sign of discoloration, the underlying insulation will likewise be sound. If the jacket is brittle or highly discolored, then the condition of the insulation will be questionable and further assessment is needed. Ohmic heating does not apply to instrument and control cables. Thermal damage to the insulation and jacketing materials occurs only from adverse environments and radiant heating from adjacent hot components. Accordingly, the jacket condition will almost always be a leading indicator for the insulation.

Figures A-1 and A-2 indicate that a 40-year-old plant with neoprene jackets would have a lower cutoff temperature for adverse environments than a plant with Hypalon jackets would. This does not mean that the underlying insulations would behave significantly differently but rather that thermal damage to the jackets would be observable sooner on the neoprene and that further assessment of the cable insulation by other means will likely be necessary sooner. Figure A-2 indicates that temperatures as low as 92°F (33°C) could lead to identifiable thermal aging of neoprene after 40 years. It must be recognized that in most plants a large portion of the plant does not experience a year-round temperature as high as 92°F (33°C).

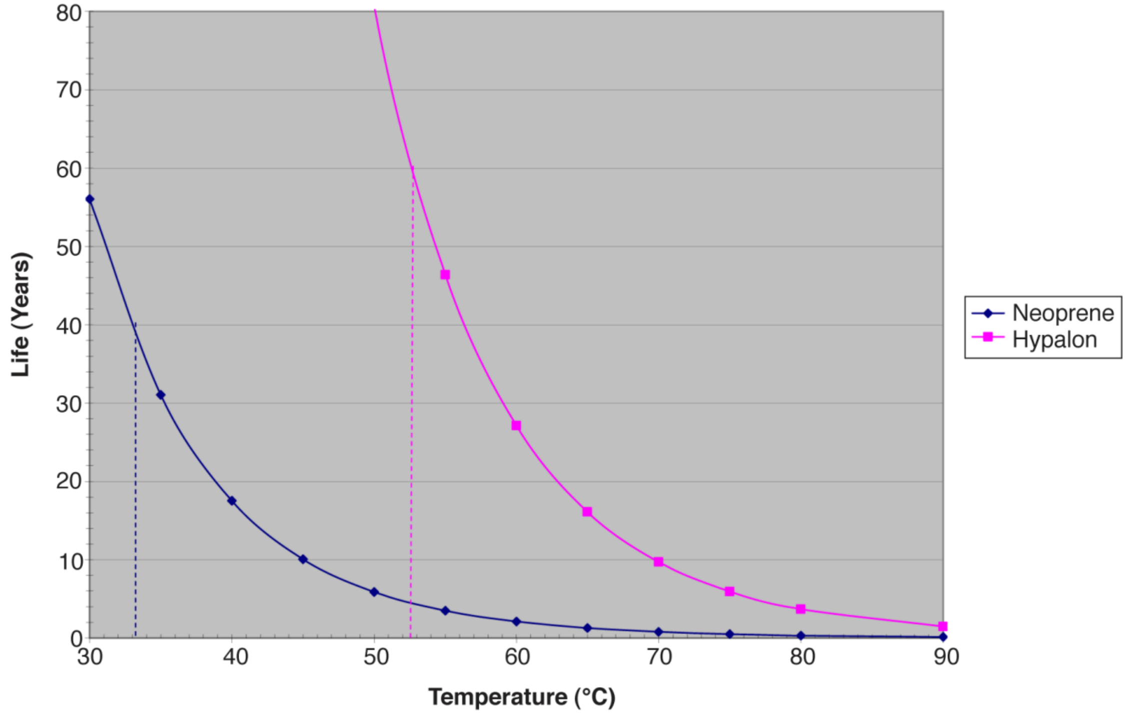

Figure A-1
Age at Which Typical Neoprene and Chlorosulfonated Polyethylene Will Reach 50% Absolute Elongation (Temperature in °C) [15]

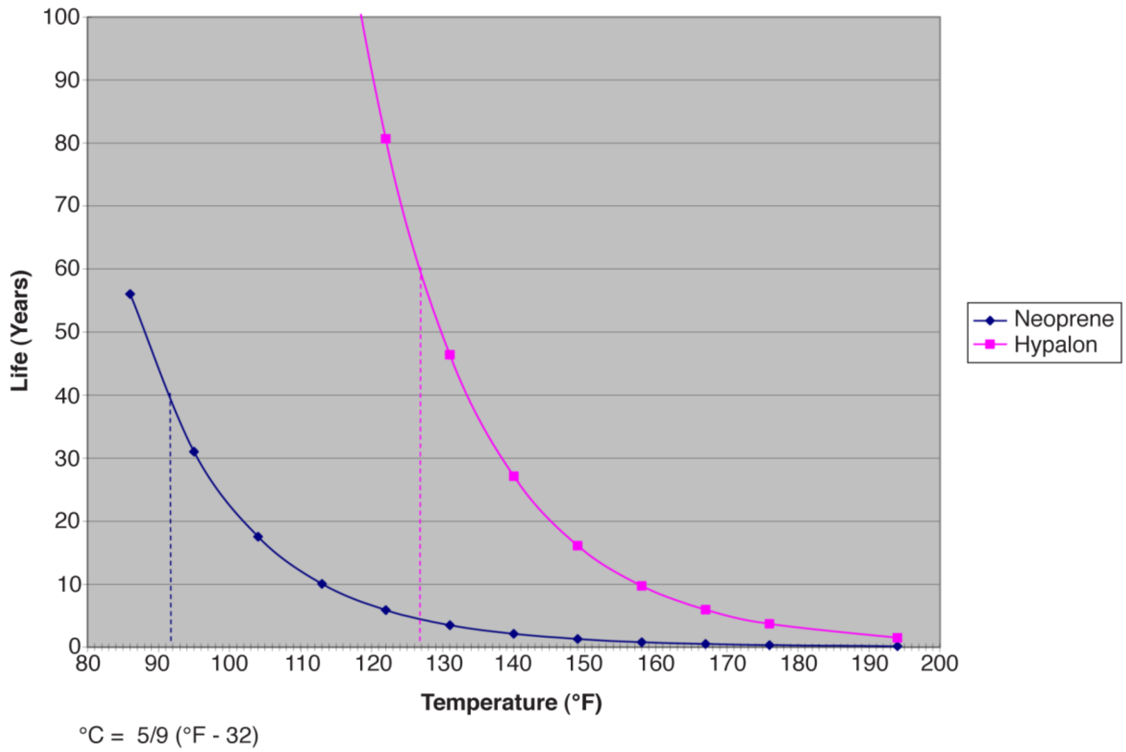

Figure A-2
Age at Which Typical Neoprene and Chlorosulfonated Polyethylene Will Reach 50% Absolute Elongation (Temperature in °F) [15]

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