Plant Engineering: Aging Management Program Guidance for Medium-Voltage Cable Systems for Nuclear Power Plants, Revision 1

2013 TECHNICAL REPORT

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This document does NOT meet the requirements of 10CFR50 Appendix B, 10CFR Part 21, ANSI N45.2-1977 and/or the intent of ISO-9001 (1994).

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Product Description

This report was prepared in response to regulatory and management concern regarding the reliability of medium-voltage cable systems at nuclear plants. The staff of the U.S. Nuclear Regulatory Commission (NRC) have been concerned that wetted (up to and including submergence) medium-voltage cable circuits may be degrading to the point at which multiple cable circuits may fail when called on to perform functions affecting safety. A utility manager's concern is that cables may fail, causing adverse safety consequences and/or plant shutdowns. This report provides guidance for developing and implementing a cable aging management program for medium-voltage cable circuits in nuclear power plants.

This revision incorporates lessons learned from the initial implementation of aging management programs and additional EPRI technical findings. Failure mechanism research has identified that cables in relative humidity higher than 60% should be considered to be subject to water-related degradation, albeit at a much reduced rate then submerged cables. Recent operating experience on thermal aging of cables in motor termination boxes has been included in Section 3 under "thermal aging." The substantive changes have been to Section 5 on actions for cables in wet environments. Tan δ test criteria are no longer preliminary as they have been validated through the analysis in Electric Power Research Institute (EPRI) report 1025262. Percent standard deviation is no longer listed as a separate criteria to preclude confusion on its use and is now included in the table for the other acceptance criteria in Tables 5-1 to 5-4. Due to changes in the IEEE Std. 400 series, cross-linked polyethylene cable acceptance criteria are now found in Table 5-1 of this guidance. Butyl rubber and black ethylene propylene rubber are now combined into a single table (Table 5-2).

Background

The need for a guide for developing aging management programs for cable systems has been increasing over the last few years. This report was developed with strong input from the industry and represents good practice for the foreseeable future. Cable aging management is an evolving process and an enhancement of the maintenance program for nuclear plants. The implementation process has matured, but if further research is performed that improves test technology or our understanding of degradation mechanisms, assessment criteria refinement, the focus of the programs, or the methodologies used, then another revision may be warranted.

Objectives

This report was developed at the direction of utility management and in parallel with the Regulatory Issue Resolution Protocol for Inaccessible or Underground Cable Circuit Performance Issues at Nuclear Power Plants that was developed between the NRC and the industry (through the Nuclear Energy Institute) from mid-2009 into 2010. Implementation of this guide will form part of the closure process for the protocol. This guide was prepared to provide a consistent methodology for the industry to follow in developing an aging management program for medium-voltage cable circuits that are subjected to adverse environmental or service conditions that could lead to degradation of the insulation systems.

Approach

This guide provides a way of determining the scope of a cable aging management program and focuses the aging management process on cables in the worst-case adverse environment and service conditions. It describes testing and assessment criteria and potential corrective actions. The bases for program development are provided as a way of determining the health of the resulting aging management program.

Results

The report was developed by subjecting drafts to review and revision by a Technical Advisory Group formed of industry cable personnel from nuclear plant organizations, cable manufacturers, and cable test companies. This report describes 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 subject to adverse conditions. For key test methodology, assessment criteria are described, along with possible corrective actions that could be implemented.

Applications, Value, and Use

This guide describes a common approach for developing and implementing an aging management program for medium-voltage cable systems. Techniques applicable to shielded and non-shielded cable are provided. Because the nuclear industry generally uses different cable types and designs from those used in the power distribution industry, initial assessment criteria and guidance pertinent to the cable applications in the nuclear industry are provided.

Keywords

Cable aging management
Cable aging management program
Cable program
Implementation guide
Medium-voltage cables

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Section 1: Introduction

This report provides guidance for the development of an aging management program for medium-voltage cable circuits in nuclear power plants in order to ensure high reliability. The program is intended to identify adverse localized environments and adverse service conditions that could lead to early failure of medium-voltage cable circuits and to manage significant aging effects to preclude in-service failure. Low-voltage power cables have been addressed in a separate Electric Power Research Institute (EPRI) report, *Plant Support Engineering: Aging Management Program Development Guidance for AC and DC Low-Voltage Power Cable Systems for Nuclear Power Plants* (1020804) [1]. Additionally, low-voltage instrument and control cables are addressed in *Plant Support Engineering: Aging Management Program Development Guidance for Instrument and Control Cable Systems for Nuclear Power Plants* (1021629) [2]. It is recognized that one cable program can cover all cable types. However, because different aging mechanisms and assessment activities apply to instrumentation and control low- and medium-voltage power cables, the guidance has been generated separately.

This revision incorporates lessons learned from the initial implementation of aging management and subsequent EPRI technical findings. Failure mechanism research has identified that cables in relative humidity >60% should be considered to be subject to water-related degradation [30], albeit at a much reduced rate then submerged cables. Recent operating experience on thermal aging of cables in motor termination boxes has been included in Section 3 under "thermal aging." Substantive changes have been made to Section 5 to clarify actions for cables in wet environments. Tan δ test criteria are no longer preliminary as they have been validated through the analysis in EPRI report 1025262 [26]. Standard deviation is no longer listed as a separate criterion to preclude confusion on its use and is now included in the table for the other acceptance criteria in Tables 5-1 to 5-4. Due to changes in the IEEE Std. 400 series, cross-linked polyethylene cable acceptance criteria are now found in Table 5-1 of this guidance. Butyl rubber and black ethylene propylene rubber (EPR) are now combined into a single table (Table 5-2). The proper use of insulation resistance as it applies to cable has been incorporated.

Medium-voltage cables (rated 5 kV to 46 kV[1] and generally having operating voltages between 2.3 kV and 34 kV) may age and fail because of several mechanisms. Table 2-2 of EPRI report *Equipment Failure Model and Data for Underground Distribution Cables: A PM Basis Application* (1008560) [3] lists the potential failure mechanisms and whether they are random or age related. The random causes such as installation damage or manufacturing defects do not affect any significant portion of the population of cables and, as such, are not addressed in this report. This document pertains to long-term aging from adverse service conditions that, if neglected, could lead to in-service failures. The effect of a medium-voltage cable failure can cause the loss of a train of a safety system or remove an offsite feed from service. Accordingly, an aging management process for medium-voltage cable systems is desirable to limit the number of in-service failures and support high reliability of the medium-voltage cable system.

Medium-voltage cables and accessories that are properly installed, supported, and kept cool and dry should have a long life. However, cables or accessories that are subject to adverse conditions should be governed by an aging management program. The following are recognized adverse conditions with respect to the longevity of medium-voltage cable circuits:

- Adverse localized high-temperature and/or high-radiation ambient environments under normal operating conditions
- High conductor temperature from ohmic heating
- High-resistance connections at terminations or splices
- Long-term submergence (partial or full submergence)[2]

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 circuits. Accordingly, for benign environments and service conditions, monitoring and maintenance are not expected to be necessary. Further action would be required only if failures occur or degradation from very long service is recognized. 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 [4] and plant corrective action programs.

If one or more adverse conditions are observed, further assessment, testing, and/or corrective action will be necessary to ensure reliability, unless the cable and/or its accessories have been designed for the conditions.

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[1] This definition of *medium voltage ratings* is from the Insulated Cable Engineers Association Standards. NUREG-1801 XI.E3 defines *medium voltage* as 2 kV to 35 kV (assumed to be the range of operating voltages).

[2] Susceptibility is also a consideration. Lead sheath cables and other water impervious designs (that is, continuous, corrugated, sealed copper shields) are not affected, and certain polymers have shown resilience (modern pink and brown ethylene propylene rubber (EPR) insulations). Cross-linked polyethylene, Butyl rubbers, black EPR, compact design EPR (black and pink) have proven to be susceptible to submergence-related degradation. See Section 4 for more.

Program Development

> ***Program Element 1***
>
> Each nuclear power plant should have an aging management program for medium-voltage cable systems. 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 appropriate performance indicators.

A program plan should be developed for aging management of medium-voltage cable circuits. The plan should include the following elements:

- Management's objectives for the program (that is, 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)
- A well-structured process including scoping, identification of adverse environments and service conditions, assessment of cable circuits exposed to the adverse environments and conditions, and implementation of corrective action as appropriate
- Defined roles and responsibilities including those for the program manager and supporting organizations for assessments, tests, and repair or replacement
- Training requirements
- Determination of the scope of cable circuits to be in the program (see Section 2)
- A schedule for completion of the scoping, the determination of the cable circuits potentially affected by adverse environments and service conditions (see Section 3), and the development of the initial assessment plan and expected cost for adoption
- Management sponsorship of continued implementation
- Program health reporting and corresponding performance indicators
- Documentation to be retained, including scope determination, adverse service conditions, cable circuits to be assessed, condition and cable assessment methods, condition and cable assessment and test results, and corrective actions that have been implemented
- Periodic review of plant conditions to determine whether there have been any changes to adverse conditions (additions or deletions)

Implementing Procedures

Implementing procedures[3] should address the following:

- Roles and responsibilities
- Scoping methodology and documentation
- Determination of adverse conditions
- Consideration of susceptibility of the plant cables to adverse conditions and identification of cable circuits needing assessment
- Schedule of initial assessments and periodicity of subsequent assessments
- Methods to be used to assess cable circuits subject to adverse conditions
- Assessment of results related to cable condition
- Repair or replacement options (see Section 7)

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 (for example, cable circuits subject to the Maintenance Rule and additional License Renewal Rule required scope).
- Cable circuits within the program that are subject to adverse localized environments and/or service conditions that require aging management.
- Additional information that should be identified for these cable circuits includes the following:
  - The nature and location of the adverse environment or service condition.
  - Cable circuits that are affected, including the subcomponent of concern (for example, termination, splice, or cable).
  - Associated load of affected cable circuits (for example, specific motor, bus, or transformer).
  - Degradation mechanism of concern (for example, thermal damage or voltage/water degradation).
  - Method of assessing or monitoring the effect and the periodicity of assessment (for example, one-time assessment, periodic visual inspection, or periodic test [including initial assessment interval]).

[3] 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.

- Methodology of assessment and tests. (Given that periods between assessments and tests may be several 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 improve.)
- Results of assessments and tests.
- Repair and replacement descriptions.

- Where 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 adequate.
- The scope of the program is clearly defined.
- The adverse localized environments and adverse service conditions of concern have been defined.
- The cable circuits within the program that are subject to adverse localized environments and/or adverse service conditions have been identified for further aging management activities.
- For cable circuits requiring further aging management activities, a method of assessing the cable has been identified and scheduled.

Program Health Indicators

The following are suggested program health indicators:

- The cable circuit/adverse environment assessments are being implemented according to schedule.
- Deferral of cable circuit assessments is limited.
- Review of cable circuit assessment results is timely, and corrective actions are initiated.
- Implementation schedule of corrective actions is met.
- Control of cable submergence is satisfactory.

- Control of thermal insulation in the vicinity of power cables is adequate.
- Thermography of connections and high-current cables is being performed and acted on.
- Program self-assessments are being performed at a reasonable interval.
- The number of age-related cable circuit failures during a defined period is within prescribed limits.
- The number of open findings or areas for improvement from external audits or assessments (for example, U.S. Nuclear Regulatory Commission [NRC] and Institute of Nuclear Power Operations [INPO]) is limited, and they have been resolved in a timely manner.
- Forensic assessment of cables that fail in service is performed, and the findings are incorporated into changes or improvements to the program.
- Applicable operating experience of other sites is being reviewed, assessed, and incorporated into the cable program by the program manager.

Definitions

assessment: In the context of this report, *assessment* is used to cover a broad range of activities regarding cable 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 physio-chemical 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, as a result of the presence of adverse service or environmental conditions.

delta tan δ: Delta tan δ is the value yielded by the difference between the tan δ readings at 0.5 V_0 and 1.5 V_0. It can also be the difference in tan δ readings between V_0 and 2 $V_{0.}$ When testers choose to limit test voltage (V_t), delta tan δ may be expressed in terms of 0.5 V_t and V_t.

impervious coverings: Some utilities have and continue to purchase and install cables with impervious coverings, which are designed to prevent penetration of water into the insulation system. Earlier cables used continuous lead or aluminum coverings tightly formed over the core of the insulation, including cable shields.[4] These continuous layers preclude water ingress, and the result is a dry insulation that is not subjected to wetting even if the cable is completely submerged.

[4] For example, for a 1-in.- (25.4-mm-) diameter core, the required lead layer was 80 mils (2.03 mm), and the required aluminum layer was 55 mils (1.4 mm). A more modern design of water-impervious cable uses a continuous linearly corrugated copper tape system that is wrapped around the cable core with the overlap glued shut (See IEEE Std 400-2001, Section 4 [14]).

Impervious coverings are optional and not required for submerged applications. They are most often chosen when particularly aggressive soil or water conditions exist.

inaccessible cable: Inaccessible cables are those cables that have sections located below grade or are imbedded in the plant base mat and that are located in duct banks, buried conduits, cable trenches, cable troughs, underground vaults, or that are direct buried.[5]

The concept of inaccessibility for cables is related to the ability to determine the environment and physical condition of the 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, heat sources that are close to the tray or conduit are relatively easy to identify, and further assessment of the cable's condition is possible. Inaccessibility is not a concern if adverse service and environments do not exist.

submergence, wet, damp, and dry locations: The Underwriters Laboratories, Inc. (UL) and the National Electric Code (NEC) 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 NEC definition indicates "saturation with water or other liquid," and the UL definition indicates "flow on or against electrical equipment."

[5] 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…" [5]. 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" [6].

Table 1-1
National Electric Code and Underwriters Laboratories, Inc. definitions of dry, damp, and wet locations

Term	National Electric Code Definition [7]	Underwriters Laboratories Definition [8]
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 beneath 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. (Could be condensing moisture, does not need to be submerged.)	A location in which water or other liquid can drip, splash, or flow on or against electrical equipment.

Abbreviations and Acronyms

The following abbreviations and acronyms are used in this report:

ac	alternating current
CPE	chlorinated polyethylene (thermoset or thermoplastic)
CSPE	chlorosulfonated polyethylene (commonly referred to by the DuPont trade name Hypalon)
dc	direct current
EOP	emergency operating procedure
EPR	ethylene propylene rubber Black EPR is the earliest generation of EPR used as cable insulation. Later generations were either gray (substantially reduced levels of carbon black), pink (red) EPR (most manufacturers), or brown EPR (Kerite). The color differences were to allow visual distinction between black semi-conducting or high permittivity shields and the insulation and also to demark the transition to improved coatings of the filler clay to improve its bonding to the base insulation material and preclude absorption of water.
GALL	Generic Aging Lessons Learned report
Gy	gray; a metric unit of radiation equal to 100 rad
HCl	hydrogen chloride
hi-pot	high potential, also referred to as "withstand test"
hr	hour
INPO	Institute of Nuclear Power Operations
kV	kilovolt(s)
LIRA	line resonance analysis (a cable condition monitoring technique)
Mrd	megarad
NEI	Nuclear Energy Institute
NEC	National Electric Code
NRC	U.S. Nuclear Regulatory Commission
PM	preventive maintenance

PVC	polyvinyl chloride
rd	rad
rms	root mean square
tan δ	An ac dielectric test of insulation that measures the ratio of resistive leakage current to the capacitive current across the insulation (radians, often given in terms of 10^{-3})
TDR	time domain reflectometry
UL	Underwriters Laboratories, Inc.
VLF	very low frequency
V_0	line-to-ground rms voltage on a three-phase system, also referred to as U_0
Vt	limited test voltage
XLPE	cross-linked polyethylene

Section 2: Scope of the Aging Management Program for Medium-Voltage 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 aging management program for medium-voltage cable systems. It is recommended that additional cable circuits associated within the scope of the License Renewal program be included in the scope of the aging management program for medium-voltage cable systems. These cable circuits may be included in the initial scope or added to the program when implementation of License Renewal Rule actions is required. Any commitments related to medium-voltage cable aging management contained in plant-specific regulatory correspondence should also be included in the development of the program and its scope.

Cable circuits required to support AP-913 critical functions should be considered for inclusion in the scope of the aging management program for medium-voltage cable systems. Medium-voltage cable circuits critical to power generation, or that may result in outage length extension should they fail, may be added to the scope of the program at management option.

Those who are developing the scope of the cable circuits to be within the aging management program for medium-voltage cable systems should consider these sources:

- The Maintenance Rule (10 CFR 50.65) scope requirements [3]
- The License Renewal Rule (10 CFR 54) scope requirements [9]
- Updated Final Safety Analysis Report commitments (if any)
- License Renewal Rule aging management program commitments

- Plant-specific regulatory correspondence pertaining to cable
- 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 and the License Renewal Rule. Paragraphs 10 CFR 50.65 (b)(1) and Paragraph 10 CFR 54.4(a)(1) require that cable circuits supporting safety-related functions be within the 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 cable circuits whose failure could prevent safety-related functions from being fulfilled be within the scope. Paragraph 10 CFR 50.65 (b)(2) also requires that cable circuits used to mitigate accidents or transients or to support emergency operating procedures, as well as cable circuits whose failure could cause a reactor scram or actuation of a safety-related system, be in the scope. Paragraph 10 CFR 54.4(a)(3) extends beyond the Maintenance Rule scope in that cable circuits related to station blackout and fire protection are within the scope.

Some plants may have cable monitoring commitments in their Updated Final Safety Analysis Report. All plants that pursue license renewal will have cable aging management commitments in the License Renewal Rule aging management program for cable and connections and terminations. Under the license renewal process, 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 aging management program for medium-voltage cable systems. Some plants may have cable-specific regulatory correspondence pertaining to cable. Review of the plant-specific response to Generic Letter 2007-01 is appropriate to confirm the activities that the plant stated were in place to assess the condition of cables and to control the wetting of cables [6]. As the plant's aging management program for its medium-voltage cable system is developed and implemented, it is recommended that differences from and changes to methodologies 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 required to support the function of components should be considered with respect to the scope of the aging management program for medium-voltage cable systems.

Medium-voltage cable circuits that supply outage power whose failure may adversely affect outage duration should also be considered for inclusion in the scope of the program. Other cables may be identified for scope inclusion based on plant-specific experiences.

Table 2-1
Scope comparison for Maintenance Rule, 10 CFR 50.65, and License Renewal Rule, 10 CFR 54 [4, 9]

Maintenance Rule	License Renewal	Differences
10 CFR 50.65 (b)(1) Safety-related…systems and components that are relied on 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 on 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 on 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.	Agreement on non-safety components that could affect function of safety components. The Maintenance Rule adds cables associated with EOPs and that could result in scrams or safety system actuation.

Table 2-1 (continued)
Scope comparison for Maintenance Rule, 10 CFR 50.65, and License Renewal Rule, 10 CFR 54 [4, 9]

Maintenance Rule	License Renewal	Differences
	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).	License Renewal Rule adds cables associated with fire protection, station blackout, and anticipated transient without scram. Environmentally qualified cables would be in scope already; there are no cables associated with pressurized thermal shock.

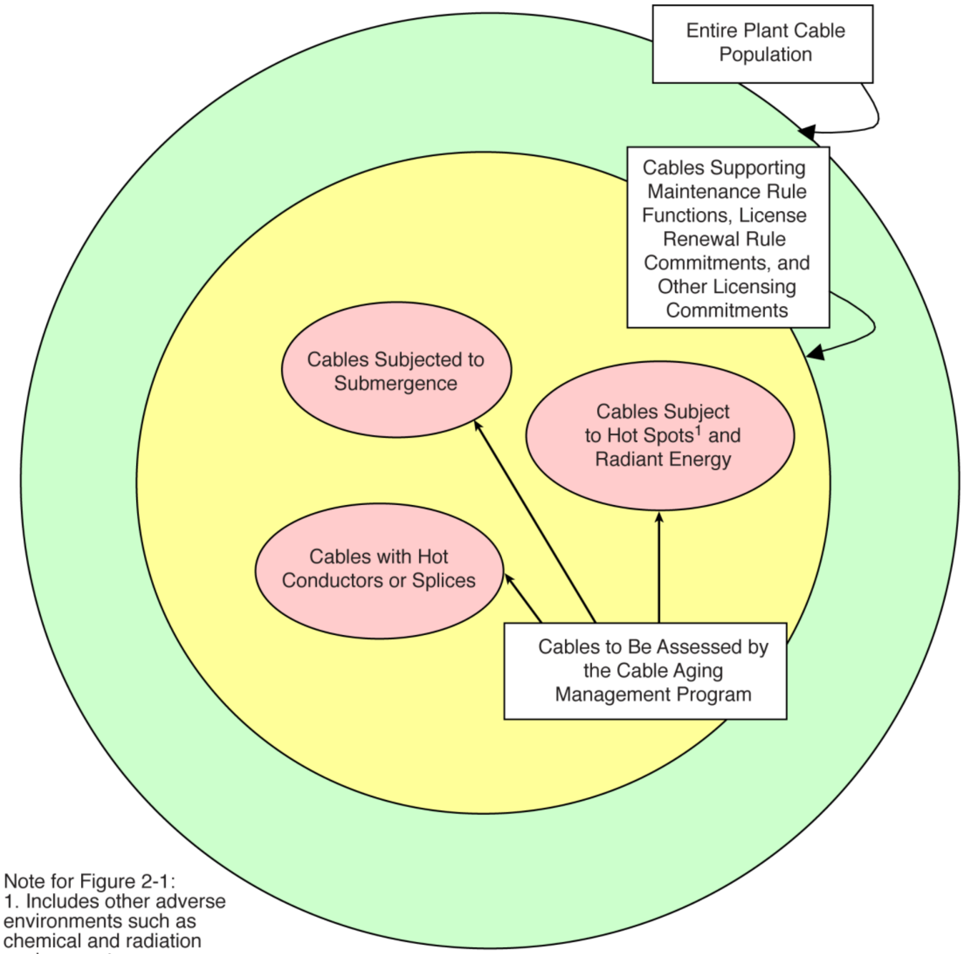
Program Scope Versus Cable Circuits Requiring Condition Monitoring or Assessment

The purpose of scoping is to consider the extent of cables that would need condition assessment or monitoring if they were exposed to adverse environments or have adverse operating conditions. It is not the intent of the program to assess and monitor the condition of the entire program scope. Rather, this document requires the assessment of cables and/or accessories[6] 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 aging management program for medium-voltage cable systems as appropriate.

For medium-voltage cables, the list of cable circuits under consideration will likely be determined by a review of medium-voltage bus loads and offsite power sources and then by a determination of whether the individual circuits have elements that are subject to adverse environments or service conditions. This technique works because of the limited number of circuits involved. Figure 2-1 illustrates the scoping concept.

Although this document focuses on managing the aging of medium-voltage cable circuits that are subject to recognized adverse effects, the Maintenance Rule and corrective action processes ensure that if a new failure cause is identified, it will be assessed, and corrective actions taken to control the effect. As appropriate, the aging management program for medium-voltage cable systems should be revised to take new failure causes into account.

[6] Cable accessories are splices (joints) and terminations.



Note for Figure 2-1:
1. Includes other adverse environments such as chemical and radiation environments.

Figure 2-1
Medium-voltage cable circuit scoping process

Section 3: Identification of Adverse Environments and Conditions

Program Element 3

The determination of cable circuits that are subject to adverse environments or cable circuits that are subject to adverse service conditions will be assessed as follows: Program Element 3.1 describes wetted cables that are subject to adverse conditions, and Program Element 3.2 describes cables in dry environments that are subject to adverse conditions.

After the cable circuits within the scope of the aging management program for medium-voltage cable systems have been identified, the nature of the cable layout and application must be identified to determine whether aging management activities are required for particular cables. If cable circuits are subject to benign conditions, there are no aging management concerns at this time.

The first effort will be to separate cables that are located in completely dry conditions from circuits potentially wet or known to contain wet sections. Cables having wet or potentially wet environments include cables that are inaccessible or underground and/or are in substructure segments whether they are installed in ducts or trenches or are direct buried. Cables located in dry accessible cable tunnels may be excluded from consideration for wetting. For cables determined to be totally in dry environments or having an impervious design, skip to "Activities for Dry Environment Cables." For cables having mixed dry and wet segments, the "Activities for Dry Environment Cables" applies to the dry sections, and the "Activities for Wet and Potentially Wet Environment Cables" applies to the wet section. In this case, dry sections relate to inside structures in trays or conduits rather than underground "dry" sections. Research [30] indicates that in underground applications once a cable has become wet, the relative humidity must be below 60% before water-voltage related degradation eventually ceases. A cable in a condensing humidity environment will not dry out and water-voltage related degradation will occur as if the cable were submerged, but at a greatly reduced rate.

Activities for Wet and Potentially Wet Environment Cables

> ***Program Element 3.1***
>
> Cable circuits subjected to long-term wetting should be identified.
>
> If cables are subjected to wetting or have been subjected to wetting for long periods in the past, aging management should be implemented, starting with the assessment of the susceptibility of the insulation to wet conditions as described in Section 4.
>
> The condition of vaults and manholes subject to wet conditions and the cable support structures within them should be evaluated at least once to determine their condition. Appropriate repairs should be made. The need and interval for further evaluations should be determined based on the conditions that are identified.

A conservative approach to the aging management of medium-voltage cable is to assume that all underground cables are wet and develop the program on that premise. This approach eliminates the need to assess the design and perform verifications that there are no wetted sections in cable circuits.

However, some underground systems have been designed to be dry or drained automatically. If the cables in such systems can be shown to be dry (for example, by verifying that water does not exist in ductwork between manholes), the concern for long-term wetting can be eliminated. This premise may be difficult to defend unless some sort of inspection evidence (for example, umbilical video inspection) can be provided to support the supposition that the conduits are water free.

"Rain and drain" applications in which a duct or manhole may be wet for a short period until natural or automated draining (for example, a sump pump) occurs are not considered adverse with respect to the life of a medium-voltage cable. Systems in which ducts slope toward manholes or other structures that are drained so that cables neither sit in nor are submerged in water for any significant period can be treated as dry with respect to cable longevity. Cables mounted on the walls of trenches and not subject to wetting along their length can be considered dry.

Water permeation into cable insulation takes a significant amount of time. For this report, *long-term wetting* is defined as a condition in which the cable sits in or is covered by water for a continuous period of months or longer. A jacket over the insulation will significantly slow the effect, but the exact degree has not been determined. After water has permeated the jacket, water is known to be drawn to the highest voltage stress concentration within the insulation, which is near the conductor surface. When the water is drained from the vicinity of the cable, the ohmic heating of the conductor may drive off some of the moisture from the insulation, but how much and how fast is not readily identifiable. Certainly, further water and the additional chemical contamination (for example, salts) in the water are no longer available to permeate into the cable. However, any degradation that may have occurred does not reverse. Rather, the rate of further degradation is assumed to be slowed by draining the ducts and manholes and keeping them drained [27]. With respect to direct buried cables, an assumption must be made that the cables are always wetted, because no observation can be made to show that they are above the water table and that there are no subterranean pockets of water surrounding sections of the cable.

If credit is being taken for a cable system being self- or naturally draining or manually pumped often enough to ensure that its cables are not wetted, at least a one-time inspection of the system to confirm its nature should be made. If automatic sump pumps are being credited for maintaining a dry cable system, an appropriate inspection and maintenance program should be in place for the pumping system so that long-term wetting of the cables will not occur. If manual pumping is used as an alternative, the pumping must be performed frequently enough to preclude long-term wetting, or manholes must be inspected after significant rainstorms, winter thaws, or flooding events to determine whether pumping is necessary and that action is taken accordingly.

Both water and voltage must be present for water-related deterioration to occur in medium-voltage cables. Accordingly, cables that are rarely energized will suffer minimal water-related degradation even if exposed to long-term wetting. However, given that the most important safety cables are likely to be de-energized for most of their service life and that less-well-understood failure mechanisms could be possible in wet environments, assessment and testing of these cables is important. These cables should be evaluated early in the implementation process of the aging management program for the cable system. If these cables are found to be in satisfactory (that is, “good”) condition after an extended period, consideration may be given to extending the period between tests with respect to continuously energized cables.

Non-Drained Conduits and Ducts Within Plant Structures

In some cases, medium-voltage cable ducts within plant structures are embedded in the floor with both end points exiting the floor above the duct. If such ducts exist and if there is no drain for the below floor section, moisture may accumulate and condense in the duct, or the duct may fill from spills or other water-related events. To the extent practical, such duct arrangements should be evaluated to determine whether they are dry. If not, the condition of the cable should be assessed, and if practical, the duct should be drained.

Condition of Vaults, Manholes, and Related Cable Support Structures

In addition to concerns for cables aging under wet conditions, support structures for cables in trenches, manholes, and vaults may degrade with time, resulting in inadequate support of cables or physical damage to the cables. The physical structure of the manhole or vault may also degrade. Accordingly, the condition of support structures (for example, brackets and trays) and the overall manholes and vaults should be evaluated to confirm that no significant deterioration has occurred. It is recommended that ladders and platforms for personnel be included in these evaluations.

Activities for Dry Environment Cables

> ***Program Element 3.2***
>
> Medium-voltage cables in the scope of the program that are located in dry environments should be reviewed to determine whether they are exposed to adverse localized environments, are subjected to elevated operating temperature from circuit currents, or have high-resistance splices or terminations. Where other programs exist that will control and identify these conditions, credit may be taken for them, and additional controls need not be added.
>
> The thermal insulation and barriers that protect cables from process heat damage must be maintained. If plants remove thermal insulation from piping and equipment adjacent to cable in preparation for an outage, the effects on adjacent cable should be addressed. Procedures for restoration of thermal insulation in the vicinity of cable circuits should be reviewed to ensure that the thermal insulation is inspected for acceptability and that adequate protection from thermal stresses is given to the cable.
>
> Motor lead cables (cables from the winding to the feeder cables) and motor feeder cables (cables from the power source to the motor) in the motor terminal box are another group of cables that may be subjected to long-term ambient conditions in excess of 50°C (122°F). Cables in these locations have been the subject of plant operating experience where the cables were found to be thermally aged to the point where insulation or cable jacket material were discolored and cracking. Heat generated by the motor winding and core were sufficient to thermally age these cables and, in some cases, resulted in phase-to-ground or phase-to-phase failures. The actions for cable found to be in adverse thermal and radiation environments are described in Section 6.

The adverse conditions and environments that can shorten the life of medium-voltage cables under dry conditions are as follows:

- High-temperature or high-dose-rate environments under normal operating conditions
- High conductor temperature from ohmic heating
- High-resistance connections at terminations or splices

The following subsections address these items and assess their importance with respect to cable longevity.

High-Temperature or High-Dose-Rate Ambient Environments

Thermal Aging

Elevated temperatures cause thermal aging and may also limit the allowable ampacity of the cable. Cable thermal ratings are based on conductor temperature in a free air 40°C (104°F) environment. Most cables in nuclear plants have been de-rated so that conductor temperatures are well below the rated temperature, and a long thermal life in a 40°C–50°C (104°F–122°F) environment would be expected. However, care must be taken in environments that exceed 50°C (122°F) and for cables operating near their ampacity limit in ambient environments of 40°C (104°F)or more because any combination of ambient temperature and high motor winding temperatures or ohmic heating can cause higher rates of thermal aging.

In general, bulk area temperatures are not expected to significantly affect the aging of medium-voltage cable. However, localized hot spots are a key concern, especially if the cable is adjacent to hot process piping. NRC Information Notice 86-49 [11] identified a 4-kV cable failure from exposure to a hot process pipe [10]. If a medium-voltage cable is adjacent to an uninsulated hot process component (for example, a pump, pipe, or valve), the cable polymer will be affected by both the local temperature and the radiant heating from the component. The circuit routing should be reviewed and/or walked down to determine whether hot process equipment is in the vicinity of the cable. If so, the condition of the thermal insulation on the hot components should be confirmed as adequate for the protection of the cable. Maintenance procedures should also be confirmed as requiring restoration of thermal insulation before the process component is returned to service if the thermal insulation must be removed to allow maintenance of the process component. If the process component must operate without insulation for any significant period, the effect on the medium-voltage cable should be evaluated. If a significant effect is expected, temporary thermal shielding should be placed between the hot process pipe and the cable.

Thermal aging of cables in terminal boxes and motor leads has shown up in operating experiences, and these areas must be included as watch areas. The motor leads are the transition cables from the motor winding to the power supply cables. They are in close proximity to the motor core and are subjected to the heat generated by the magnetic field effects on the motor. Motor leads are non-jacketed, non-shielded, and generally a smaller gauge than the power cables. Typical cables are XLPE or EPR insulated. The cable's thermal aging will be governed by the ambient temperature inside the motor and the heat generated by the motor stator and rotor. Both motor leads and supply cables have been found to be affected due to high ambient conditions in the locations between the motor winding and the motor terminal box.

Figure 3-1
Jacket cracking can be seen on these power cables in a motor terminal box that are thermally aged. Thermal aging combined with manual manipulation during maintenance ultimately led to an in-service failure

Radiation-Related Aging

With respect to radiation effects, most medium-voltage cable will be in low-dose areas of the plant. However, some cables may be located in areas with appreciable doses. Sandia research on low-voltage cables with similar compounds to those in medium-voltage cables showed that the 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 observed [12]. Assuming a 60-year desired life for a medium-voltage cable, no appreciable effect would be expected for average dose rates up to10 rd/hr (0.1 Gy/hr).[7] Although minimal effects are expected at 10 rd/hr (0.1 Gy/hr), the effects could be appreciable if the cables are simultaneously exposed to high temperature (for example, greater than 122°F (50°C) with conductor temperatures reaching ampacity limits).

The effects of radiation and temperature are to change the physical properties (such as loss of elongation and increased hardness) of the insulation and, after severe aging, to eventually affect the electrical properties. If high-temperature conditions are recognized and radiation doses greater than 5 Mrd (50 kGy) are expected, the medium-voltage cables should be inspected for degradation unless

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[7] 1.9 rd/hr = 5 Mrd ÷ (60 years × (365 days/year) × 24 hours/day)

environmental qualification data exist that show the capability of the materials. Note that until the dose from the exposure reaches approximately 5 Mrd (50 kGy), 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 (0.1 Gy/hr), that is, 15–20 rd/hr (0.15–0.2 Gy/hr).

Several types of medium-voltage 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. The thicker insulation and jackets of medium-voltage cables make them less susceptible to thermal and radiation aging. 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. Where radiation, thermal damage, or both are a concern, the initial evaluation should include a visual/tactile assessment as described in later sections of this guide.

Periodicity of the Review of Condition

The initial review of adverse conditions will identify areas, if any, with elevated thermal or radiation conditions. The need for action will be governed by the severity of the conditions. Modifications and changes to plant operating conditions that could significantly worsen thermal or radiation conditions in the vicinity of medium-voltage cable should be reviewed for their effect.

The review should identify where medium-voltage cables are in close proximity to hot process piping. Programmatic controls should be put in place to verify that thermal insulation remains intact and effective so that the medium-voltage cables are not adversely affected as could occur if the thermal insulation is taken off and left off for a significant period.

High Conductor Temperature from Ohmic Heating

Ohmic heating of medium-voltage cable from load currents can cause appreciable aging of the insulation system if cable currents cause the cables to operate at or above rated temperature, especially if ambient temperatures are elevated. Normal design practices result in operating cables at currents significantly below their ampacity. Design practices or ohmic heating calculations should be reviewed to confirm that elevated conductor temperatures (for example, >90°C [>194°F], a common cable thermal rating) should not occur.

One special case should be considered that can occur with multi-cable-per-phase circuits. When multiple cables are used in each phase, the magnetic fields must be balanced so that equal currents occur in each phase. This can be done by running three separate phase cables that are triplexed or in the same duct. However, if the individual conductors are laid flat in trays, the positions of the conductors may need to be transposed along the run to balance the magnetic circuits. If the magnetic fields are not balanced, some cables in each phase will run with lower currents and others will have high currents. Conditions have occurred in which the high-current cables were operating beyond ampacity, and thermal aging caused severe hardening of the insulation and jacket. When a fault occurred on a connected transformer, the cables thrashed and one cable's insulation cracked to the conductor. Accordingly, the current balance on multi-conductor-per-phase cables should be verified. This verification could be performed through the use of infrared thermography if cables are accessible or through measurements of current on individual conductors.

Periodicity of Review

The review of ohmic heating of medium-voltage cables and current balance on multi-conductor-per-phase circuits needs to occur only once. Re-review would be necessary only at the time of circuit modification, repair, or replacement.

High-Resistance Connections at Terminations or Splices

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 can occur, resulting in high-resistance connections, especially when connections involving aluminum conductors are being made. Accordingly, 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 can 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 or 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 program can 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. Frequencies vary based on the end load's criticality. Infrared thermography surveys should be scheduled to be performed when the equipment is energized and loaded to provide meaningful results.

In many cases, access to terminations of medium-voltage cables is limited because of equipment design, arc flash concerns, and so on. One relatively inexpensive way to improve access is by using infrared windows or infrared ports on switchgear doors and cable termination boxes. Both types of access covers are available with Underwriters Laboratory (UL) ratings equal to that of most electrical enclosures. Infrared windows are made from special materials that are transmissive (transmissive materials can pass radiant energy that glass and Plexiglas cannot), and they are more expensive than a port. In addition, they have 40%–60% transmissivity, which requires calculating hot-spot temperature by multiplying the measured value by the inverse of the transmissivity for the window, and they do not hold up well when exposed to outside environments. Infrared ports, on the other hand, are relatively inexpensive, simple to install, and allow direct viewing (no transmissive losses) of the target.

Infrared thermography should also be scheduled as post-maintenance verification whenever splices are installed or when splices or terminations are disturbed for maintenance. This check should be done at least 1 hour after the equipment has been energized and loaded (to allow thermal stabilization) or at the earliest opportunity thereafter.

Another diagnostic tool that can be applied to higher voltage terminations (6.9 kV and above) is ultrasonic partial discharge detectors that can be used to pick up arcing or other discharges within the connection.

Periodicity of Review

The plant maintenance program should be reviewed to verify that splices and terminations are evaluated on a periodic basis. Thereafter, the plant maintenance program can be credited for covering this subject.

Section 4: Susceptibility of Cables to Water-Related Degradation by Type

Program Element 4

The cables in the scope of the program subjected to long-term wetting should be identified and their susceptibility to wet aging reviewed. It is recommended that cables that are older than the periods stated in Table 4-2 and subject to long-term wetting be assessed for the effects of long-term aging in accordance with Section 5 of this report.

Differences exist in the susceptibility of various cable insulation types and vintages to water-related degradation under energized conditions. Table 4-1 indicates the differences in degree of expected susceptibility and the operating experience to date by insulation type and vintage. The older insulations are cross-linked polyethylene (XLPE), butyl rubber, and black ethylene propylene rubber (EPR). XLPE was extensively used in the distribution industry and found to degrade under wet energized conditions, especially in non-jacketed cables used in power distribution applications. (Nuclear plant cables are jacketed.)

The EPRI report *Equipment Failure Model and Data for Underground Distribution Cables: A PM Basis Application* (1008560) [3] is based on an evaluation of cable in distribution system service and the development of the onset of failure expectations based on expert opinions. The result was that 30% through-wall water trees could be expected in XLPE in approximately 10–12 years of wet service. A 30% through-wall water tree was identified as the point at which the cable could be susceptible to a surge from a lightning strike that would convert the water tree to an electrical tree with relatively rapid failure thereafter. In nuclear service, cables are generally protected from lightning strikes, and the cables have lower voltage stresses, which tends to make the onset of failure later than the distribution industry operating experience. Nuclear industry operating experience indicates that the onset of XLPE failures traceable to wet aging occurred after 24 years of service.

Table 4-1
Cable susceptibility under wet conditions (population data are from the Nuclear Energy Institute's [NEI's] 2005 survey on underground cables)

Material	Manufacturers of Installed Cable	Approximate Period of Installation	Population of Installed Cables at Nuclear Plants	Oldest Nuclear Plant Cables as of 2009	Earliest Expected Onset of Water Degradation in Distribution Industry [3]	Nuclear Industry Actual Experience Discussion
XLPE	Reynolds, Cyprus, and others	1975–1980	Moderate	34 years	10–12 years	Water degradation failures have been observed in the nuclear industry starting at 24 years of service.
Filled XLPE	GE	1968	Single plant	No longer in service in wet conditions	10–12 years[7]	Failures were observed starting at 10 years of service, with many failures between 10 and 25 years.
Butyl rubber	GE, Collyer, and Okonite	1967–1972	Small	42 years	20–25 years	Water degradation failures have been observed in the nuclear industry starting at 25 years of service.
Black EPR	Okonite, Anaconda, and General Cable	Bulk 1971–1979, last 1986	Large	38 years	20–25 years[8]	There have been 26 failures to date in the nuclear industry with 20–30 years of service.
Brown EPR	Kerite	Bulk 1972–1985, some 1990–2003	Moderate	37 years	20–25 years	No water-related failures have been observed to date in the nuclear industry.

[8] This material is not covered in the EPRI report *Plant Support Engineering: Aging Management Program Development Guidance for AC and DC Low-Voltage Power Cable Systems for Nuclear Power Plants*, (1020804) [1]. The onset of significant water degradation may be somewhat earlier than listed.

Table 4-1 (continued)
Cable susceptibility under wet conditions (population data are from the Nuclear Energy Institute's [NEI's] 2005 survey on underground cables)

Material	Manufacturers of Installed Cable	Approximate Period of Installation	Population of Installed Cables at Nuclear Plants	Oldest Nuclear Plant Cables as of 2009	Earliest Expected Onset of Water Degradation in Distribution Industry [3]	Nuclear Industry Actual Experience Discussion
Pink EPR	Okonite	1978 to present	Newer plants and replacements	31 years	20–25 years	No water-related failures have been observed to date in the nuclear industry; one manufacturing defect–related failure has been observed.
Pink EPR	Anaconda/Cablec /BICC and General Cable	1978 to present	Newer plants and replacements	31 years	20–25 years	Some early failures with water combined with manufacturing defects have been observed; there have been no water-degradation-alone failures reported in the nuclear industry.
TR-XLPE	Not known	2004	Rare replacement	5 years	20–25 years	There is an insufficient population and period of service to make inferences.

For the other types of insulation commonly used in nuclear plants, EPRI report 1008560 [3] indicates that the earliest expected onset of significant water-related degradation occurs in approximately 20–25 years of wet service [3]. Butyl-rubber-insulated cables were the first type of rubber-insulated cables used in nuclear plants. Only a few plants purchased these cables before the rubber-insulated cable industry converted to black EPR. At 25 years of service, water-related failures were identified in the nuclear industry.

Black EPR replaced butyl rubber in the early 1970s and is the insulation with the largest population of cables, with approximately 48% of nuclear plants reporting its use. The first water-related failures occurred at approximately 20 years of service, and more than 26 failures[9] have occurred in the nuclear industry as of this writing. Additionally, EPRI report 1025262 [26] identified an additional 11 cables that were replaced or repaired (where the entire cable run was replaced, a new termination (1) or new splice (3) was installed, or a cable section (7) was replaced)

Brown EPR insulation, while being available to the early nuclear plants, continues to be produced. Approximately 20% of plants report its use. No water-related failures have been reported in the nuclear industry to date. There have been a few cases where defective splices have been replaced, and, in some cases, new cable sections have been installed due to zinc shield deterioration.

Pink EPR replaced black EPR in the cable industry in the mid- to-late 1970s, and approximately 30% of nuclear plants report its use. To date, the only failures related to water degradation have been associated with manufacturing defects or highly localized degradation likely associated with a local flaw, a bad splice, or a bad termination. No bulk water-related degradation and failure has been reported in the nuclear industry.

Recommendations Based on Susceptibility Assessment

Table 4-2 provides the recommendations concerning the timing of cable aging management programs for wet medium-voltage cable based on insulation type. See Sections 6 and 7 for guidance.

[9] From the 2005 NEI industry survey [18] of underground cable installation and failure information, approximately 1400 black EPR cables were originally installed underground in potentially wet conditions.

Table 4-2
Aging management recommendations based on insulation material type

Material	Manufacturers of Installed Cable	Approximate Period of Installation	Recommendation for Wetted Cable Circuits
XLPE	Reynolds, GE, Cyprus, and others	1975–1980	Implement aging management program.
Filled XLPE	No longer in use in wet circuits		
Butyl rubber	GE, Collyer, and Okonite	1967–1972	Implement aging management program.
Black EPR	Okonite, Anaconda, and General Cable	Bulk 1971–1979, last 1986	Implement aging management program.
Brown EPR	Kerite	Bulk 1972–1985, some 1990–2003	Implement aging management program for cables with more than 30 years of service.
Pink EPR	Okonite	1978 to present	Implement aging management program for cables with more than 30 years of service.
Pink EPR	Anaconda/Cablec/BICC, and General Cable	1978 to present	Implement aging management program for cables with more than 30 years of service.
TR-XLPE	Not known	2004	Implement aging management program for cables with more than 30 years of service.

Note for Table 4-2: The timing of the recommendations in this table is based on the actual nuclear plant experience for the cable types described in Table 4-1.

Susceptibility of Splices to Wetting

Most plants have short enough on-site runs of medium-voltage cable that no splices exist. Other plants have some long runs, generally to intake structures or ultimate heat sinks, that require splices to complete the circuits. Offsite medium-voltage feeds to the plants likely have splices and also may be distribution-type cables with concentric neutral wires rather than helical tape shields. Some plants may have splices in circuits where wetted sections have been replaced while the dry portion of the circuit was retained. Splices in dry sections of cables should be long lived provided they are reasonably well made. However, splices in wetted sections of cables will be more susceptible to water-related degradation if there were errors in assembly. Cables with splices in wetted sections should be included in the scope of the program, no matter what type of insulation is present.[10] Only a limited number of circuits will have splices, and an even smaller set of these is expected to be subject to wet conditions.

Very low frequency tan δ testing followed by a withstand test has been successful in locating improperly installed or degraded splices and terminations [26]. A degradation site in a cable with multiple splices can be more difficult to identify and may require removing multiple splices and re-performing the tan δ test to confirm that all degraded splices and cable segments have been identified. Alternative methods such as using a Lemke partial discharge probe or an ultrasonic acoustic probe at the surface of an energized splice can help identify those that are defective. These probes detect partial discharges in the splice that would be attenuated by the helical shield and insulation losses, making them non-detectable at the circuit terminations. In some cases, splice deterioration from internal tracking or discharging may be observable through careful assessment of infrared thermographs.

[10] Cables with wetted splices that are subject to lightning strikes (that is, aerial sections or above-ground outdoor terminations) and that do not have lightning arrestors or surge suppressors may need additional assessment or testing. Cables with wetted splices that are not subject to lightning strikes (that is, terminated inside grounded structures) should be assessed starting at the point listed in Table 4-2 for the particular cable type unless adverse plant or industry operating experience dictates that a problem may exist with the splices.

Section 5: Actions for Cables with Wet Environments

Program Element 5

If practicable, manholes and vaults should be kept clear of water that could submerge cables and cable accessories.

Cables within the scope of the aging management program for medium-voltage cables that are or have been subjected to long-term wet environments should be assessed for condition.

Wet environment cables with insulation shields should be assessed using an off-line ac test. Very low frequency tan δ is recommended for cables commonly used in nuclear plants; however, the test type should be applicable to the nature of the degradation expected and the design of the cable. Very low frequency withstand testing may be used in addition to very low frequency tan δ. Alternative tests such as dielectric spectroscopy can be used. Partial discharge testing can be used if the metallic shield configuration and insulation do not lead to excessive attenuation of partial discharge signals.

For medium-voltage cables within the scope of the aging management program for medium-voltage cables that do **not** have insulation shields, plants should require a full forensic analysis of any failure that is potentially water related, with corrective action appropriate to the findings. These plants should follow research on related cables to gain insights on the water-related aging. Laboratory testing of abandoned cable or cable removed from service that was subject to long-term water exposure can be of benefit in assessing the condition of similar cables exposed to similar environments. Cable failure and aging experience from other plants having non-shielded cables and insights from research on aging and assessment of non-shielded cables should be taken into consideration to determine whether corrective action is necessary.

Long-term wetting of energized medium-voltage cables can cause water-related degradation of the insulation. Earlier vintages (late 1960s through late 1970s) are more susceptible than modern cables,[11] especially if small imperfections existed in the insulation or at its boundaries. Cables that have either been continuously wet or wet for an extended period, whether one long wetting or several shorter but significant time periods, may have experienced degradation and should be evaluated. Electrical testing of the cable will allow assessment to determine whether significant degradation has occurred. An alternative to implementing a test program would be to replace cables based on the duration of wetting and their expected susceptibility to wetting. A cable shield is required to do off-line testing. Actions for non-shielded cable are covered separately at the end of this section. The testing discussions in this section assume the presence of an insulation shield.

Pumping of Manholes and Ducts

Removing water from around the cable will not reverse degradation that has occurred. However, it may reduce the rate at which further degradation takes place, and some moisture may be expelled from the cable if there is ohmic heating during operation. The rate of deterioration in breakdown strength should slow, and a small improvement may occur. Accordingly, instituting a pumping program, installing automatic sump pumps, or repairing failed automatic pumping systems is recommended. Research conducted on the dewatering effects on EPR cable found that cables cycled through wet to dry conditions had improved ac breakdown values than those continuously submerged [27]. However, further research [30] indicates that removing water from ducts does not necessarily cause water to leave the cable unless the humidity is very low (<60% RH), which is unlikely in most underground situations.

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 proved through periodic assessment.

Rain and drain conditions should not adversely affect jacketed cables as long as wetting does not last for more than a few days on average. Water takes several months to years to migrate into the jacket. However, once in the cable jacket, shields, and insulation, water is likely to stay in the materials unless dry air is forced through the ducts to cause the relative humidity to drop below 60%.

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[11] The use of "modern" here is considered to be those pink ethylene propylene rubber insulations manufactured in the later 1970s early 1980s and beyond that have shown through evaluation of operating experience and tan δ test data analysis to not be prone to water-related degradation. Compact design cables with pink ethylene propylene rubber insulation are excluded from this distinction based on operating experience and forensic results that indicate they have a water-related degradation mechanism.

Assessment of Condition of Shielded Cables

Three practical tests[12] are currently available for shielded extruded polymer medium-voltage cable: partial discharge, tan δ,[13] and power frequency or very low frequency (VLF) withstand.[14] Depending on the nature of the cable design and the cable or accessory (termination or splice) concern, one or more of these tests would be recommended and others would be unsuitable. These test methods may be performed at line frequency or VLF (for example, 0.1 Hz). VLF test sets are frequently favored because they are readily portable and compact in comparison to line frequency systems that often must be truck mounted because of their size and weight. It should be noted that these tests assess the insulation of the terminations and splices if they are included in the test circuit. These tests are often performed off-line with elevated voltage. When elevated voltage testing is performed, whether during plant operation or during a refueling outage, it should be done with consideration of the time, materials, and personnel required to repair or replace the cable. This is not meant to be a reason not to test cables, but to ensure that due consideration is given to the impact of a cable replacement if a cable is found to be severely degraded or if one fails during a test. Testing during a refueling outage should be performed near the start of the outage to preclude extension of the outage.

Partial discharge tests are used to detect discharges that occur in gas voids within the insulation system. The discharges occur when the electric stress across the void is high enough to cause a breakdown of the gas void. The voltage is then distributed across the remaining intact insulation. Partial discharge can also occur along a surface interface or between a floating conductor and an energized electrode. For example, a partial discharge can occur on the outside of the insulation shield between the shield and a corroded tape or wire. Each discharge causes a small amount of damage to the surface of the insulation in the void causing a carbonized path to develop through the insulation, which can eventually lead to cable failures. Partial discharges result in high-frequency, low-energy signals that can be attenuated. Partial discharges in the insulation at operating voltage create electrical trees, which can propagate through the insulation relatively rapidly (for example, days to months). It should be noted that surface discharges are not as harmful and do not cause rapid damage. Accordingly, understanding the nature of the discharge involved is important and is part of the art of interpreting partial discharge results.

Offline partial discharge testing is an elevated voltage test that can be performed at line frequency or VLF. Partial discharge testing can locate the site of the discharge along the length of the cable. Partial discharge testing may be most useful in detecting termination and splice problems, especially on off-site cable

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[12] Other tests are available but are not commonly performed in the United States: oscillating wave partial discharge assessment, return current assessment, and return voltage assessment.

[13] Dielectric spectroscopy is a related test in which the insulation is subjected to dielectric assessment at multiple frequencies and voltage levels.

[14] The informal term for withstand testing is "hi-pot." In this document, *withstand testing* is synonymous with high-potential (hi-pot) testing.

feeds, and is useful for commissioning tests of new installations. However, water-related degradation, such as water treeing, does not produce partial discharge signals. In addition, in the case of helical tapes, corrosion of the tapes from long-term wetting is likely to severely attenuate partial discharge signals and impede their detection. Accordingly, partial discharge testing is likely to be unsuitable for evaluation of most of the wetted medium-voltage cables in use in nuclear plants.

Tan δ testing (also called dissipation factor testing) determines the ratio of the resistive leakage current through the insulation divided by the capacitive current and provides a figure of merit relating to the condition of the insulation. It is, therefore, also independent of the length of cable. Tan delta has no units[15] and is generally a small number given in terms of 10^{-3}. Tan δ is a bulk test and does not provide specific location information for identified degradation. It can be performed at line frequency or VLF and is generally performed at discrete voltage levels of 0.5, 1.0, 1.5, and 2 times line-to-ground voltage (V_0) (but no greater than the withstand voltage level derived from IEEE Std. 400.2 [13]).[16] Tan δ values that are elevated or unstable at a particular test voltage level or values that increase or decrease significantly with increase in voltage are indicative of deteriorated insulation. This test can identify insulation systems with distributed water-related degradation. However, if a cable insulation system has only a single but significant flaw; tan δ may not necessarily detect it. In addition, the test does not discriminate between many widespread limited degradations and a smaller number of more severe degradations. VLF withstand testing may be used to identify severe localized conditions as described next.

Dielectric spectroscopy is a related test that performs tan δ measurement at several frequencies and voltages.

VLF withstand testing applies an elevated voltage across the insulation of a cable for a significant period in an attempt to purposely cause a significantly weakened location in the insulation to break down during the test. The test is generally a go/no-go test. The concept is that if the insulation does not break down during the test, it will perform satisfactorily for a reasonable period. The test detects localized, significant degradations, but provides no information concerning widespread, low-level water degradation. VLF withstand test voltage levels and durations are defined in IEEE Std. 400.2 [13]. Some testers are evaluating longer duration, lower-level tests. Some VLF units measure the real part of the complex current providing the insulation resistance or “megohm” value. (Note: 60 Hz testing is acceptable, but provides less discrimination between good and bad insulation tan δ values [30]. In general, practical limitations of the portability of the test equipment and limited space within the power plant may preclude its use.)

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[15] Technically, tan δ is the measurement of an angle in radians, but it is rarely expressed that way.

[16] IEEE Std. 400.2 provides withstand test voltages that are applicable to all of the extruded insulation systems in use in nuclear plants.

Effects of Shield Design and Insulation on Long-Term Testability and Test Selection

Wet aging of medium-voltage cables affects two components of the cable: the metallic components of the shield and the insulation. When water migrates through the jacket, it causes a light corrosion of the metallic shield. Although light corrosion does not adversely affect the main functions of the shield, it can adversely affect its testability when attempting to use high-frequency measurement techniques such as time domain reflectometry (TDR) or partial discharge techniques [14]. The following four basic types of metallic shield are in use in nuclear power plant cables:

- Helically wound tapes
- Distributed drain wires
- Longitudinally corrugated copper shield
- Concentric neutral wires

Helically wrapped copper[17] tapes are the most common type of metallic shield. These are used in most XLPE and EPR nuclear plant cables. The helical tape allows reasonable flexibility by comparison to large conductor, concentric neutral wire systems. The next most common shield is used in the UniShield compact design and uses six drain wires that parallel the conductor. The least commonly used design in nuclear plants is the concentric neutral design, in which large strands of wire or straps are arranged around the entire surface of the semiconducting shield. This design is common in distribution systems and can be found in off-site feeds. The newest shield design is the longitudinally corrugated copper shield, which is made by forming a longitudinally corrugated copper sheet around the polymer shield and sealing the overlap. This type of shield provides a continuous barrier to keep moisture from entering the insulation system and should improve the ability to test for partial discharge because the tube presents low impedance to high-frequency signals even if light surface corrosion occurs.

Corrosion of a helical copper tape shield is the most problematic for high-frequency diagnostic techniques such as time domain reflectometry and partial discharge testing. When the copper tape is new, the tape shield acts as a tube that provides a good conducting path for high-frequency signals. If partial discharge were present, the new tape shield would present little attenuation. However, with light corrosion on the surface of the tape, the lapping of the tape becomes insulated from one wrap to the next. At this point, the helical tape acts as an inductor, especially to high-frequency signals such as partial discharge. Accordingly, deteriorated tape shields are likely to occur at the same time as the potential for deteriorated insulation. In cases in which the attenuation resulting from metallic shield corrosion prevents a reflection of the test signal from the far

[17] A limited number of cables have used zinc tapes instead of copper.

end of the cable, it prevents the detectability of partial discharge signals that may occur in or near the wet section. To a lesser extent, the insulation also attenuates the high-frequency signals; XLPE has the least attenuation, EPR has higher attenuation, and butyl rubber has the highest.

If partial discharge testing is to be used on wet cables that have tape shields, a pulse should be injected, and using TDR techniques, the sensitivity and high-frequency transmission characteristics of the cable should be determined to verify whether the shield condition is adequate to support partial discharge testing. Light corrosion on the distributed wire, concentric neutral, and longitudinally corrugated copper-type shields should not cause excessive partial discharge test signal attenuation. Although this phenomenon affects the ability of certain diagnostic techniques to assess the condition of the cable, there is no evidence that it is detrimental to normal operation or the reliability of the cable.

The choice of test depends on the nature of the problem that is of concern. In most cases, the concern for wetted cable is water-related insulation degradation (for example, water treeing). However, in cases in which splices have been used in the system, partial discharging or tracking within the splices could lead to failure. Most cables in nuclear plants do not have underground splices. However, in cases in which underground splices exist and attenuation resulting from metallic shield corrosion is not a concern, partial discharge testing may be appropriate and useful.

Water-related degradation of the insulation does not in itself generate electrical discharge signals. Only when the water-related degradation (for example, a water tree) is so severe that the electric field in the surrounding good insulation is excessive (that is, high enough to cause a water tree to convert to an electrical tree) and partial discharge begins does the degradation generate electrical discharge signals. Water-related degradation is a long slow process; partial discharges that would lead to failure occur and are detectable only late in the degradation cycle. However, as the water-related degradation progresses, the electrical leakage current through the insulation increases, and tan δ testing, which measures this leakage current in relation to the capacitive charging current, has been able to detect the degradation. The limitation of tan δ testing is that it does not provide the specific location of the defects.

Combined Tan δ and Withstand Testing

The foregoing description indicates that tan δ measurement is most likely to be useful for detection of water-related degradation for the cable designs commonly used in nuclear plants (for example, lossy insulations with or without helical tape shields). Tan δ could be complemented with VLF withstand testing. Passing a withstand test after a successful tan δ test indicates that there is no significant distributed or local degradation in the insulation system. The tan δ testing evaluates the cable for water-related degradation, and the VLF withstand test determines whether severe localized degradation exists. The tan δ test is a global assessment that identifies more widespread deteriorations in the insulation system. Because it provides more of an "average" result over the length of the insulation, it might not be as sensitive to a single local defect. The VLF withstand test, on the other hand, does not provide an indication of the overall aging of the insulation but is designed to force a significant local degradation to failure.

The use of a VLF withstand test following a VLF tan δ test is an engineering decision. For cables having a tan δ result that is "good," a VLF withstand test is optional. However, consideration should be given to performing a VLF withstand test if a "further study required" result occurs. Cable with an "action required" result should be withstand tested if there is a desire to return the cables to service. If the withstand test does not cause a breakdown of the insulation, the condition is likely to be less severe—but more widely distributed—defects rather than a large localized defect. Successfully passing a withstand test provides some assurance that the cable is acceptable for a reasonable period of service, but it does not necessarily indicate that the cable is satisfactory for an extended period. Plans should be made for further investigation of the "action required" test result or for cable replacement based on the importance of the circuit with regard to risk, safety, and operational effect.

One concern regarding the VLF withstand test is that the test may cause an already severe defect to progress toward failure, but that the duration of the test is not sufficient to bring the defect to failure during the test. As a result, failure could occur during the next period of operation. One way of gaining insight about whether the cable insulation is free of significant defects and that "partial completion" of a failure has not occurred is to perform the VLF withstand while measuring tan δ. If the cable passes the withstand test and the tan δ value is stable throughout the withstand test duration, partial completion of a degradation is unlikely to have occurred. If the cable passes the withstand test and if the tan δ is increasing or decreasing during the application of voltage, partial completion is likely, and further investigation or extension of the test period is recommended.

An alternative to coupling tan δ testing with VLF withstand testing would be to couple tan δ testing with partial discharge testing. The tan δ test would assess the cable for distributed water-related degradation, and the partial discharge test would assess it for localized, severely degraded conditions. The use of partial discharge testing would be predicated on the cable having acceptable metallic shield attenuation levels for detection of the high-frequency signals related to partial discharge. Similarly, dielectric spectroscopy could be coupled with partial discharge testing.

Tan δ Methodology and Assessment Criteria

Tables 5-1 through 5-4 provide criteria for assessing cable insulation degradation through tan δ testing. IEEE Std. 400-2004 previously contained assessment criteria for XLPE insulation [15]. This guidance has been removed from the 2012 edition of the same standard. The assessment criterion provided in Table 5-1 for XLPE insulations is what was in the 2004 revision of IEEE 400.2. The criteria for both XLPE and EPR insulation in the IEEE 400.2 2012 guidance are less stringent than the EPRI criterion contained in this document. While the 2012 IEEE 400.2 criteria may be acceptable for commercial industrial applications, distribution cables, and non-nuclear power plants, they will not provide the level of reliability expected for nuclear power plant equipment. The EPRI analysis [26] of tan δ test results indicates that the values recommended in this report provide the proper classification of cable condition and that these values should be used for condition assessment.

Tan δ testing is typically performed in steps from 0.5 V_0 (V_0 is the phase-to-ground rms operating voltage), V_0, 1.5 V_0, and 2 V_0. There have been cases where utility test personnel have limited the upper test voltage step to V_0 and have used 0.25 V_0 steps. If this is the case, then the difference in tan δ should be calculated between the second and fourth voltage step (0.5 V_0 and V_0). The following tables provide guidance for performing this analysis regardless of the test voltage steps used. Tan δ and percent standard deviation should be evaluated for each voltage step. The cause for exceeding the tan δ magnitudes or acceptable percent standard deviation at any test value should be determined. The tan δ value should change very little as the voltage is raised and should remain stable during the application of voltage at each step (as indicated by the percent standard deviation). If the tan δ value is elevated or if there is a significant increase in the value as voltage is increased (elevated delta tan δ), the cable is considered to be in an aged condition and likely in a deteriorated state.

Tan δ Percent Standard Deviation Assessment Criteria

The percent standard deviation of a set of tan δ measurements at a particular test voltage provides additional information relating to the onset of degradation. The percent standard deviation of the tan δ measurements identifies whether the tan δ value is stable or changing during a voltage step. The percent standard deviation is an additional indicator of instability in the insulation, especially at lower test voltages, even when the tan δ and delta tan δ values may still be within acceptable limits. Some test sets automatically calculate the percent standard deviation (standard deviation times 100 [for example, for a standard deviation of 1.5×10^{-3}, the percent standard deviation would be 0.15]). Other test sets require the user to calculate the standard deviation from the individual measurements. The formula for determining the percent standard deviation and an example of the data are contained in Appendix A. The consideration of percent standard deviation is especially important for tests in which the test voltage is limited to 1.0 V_0, as may occur when replacement cable is not immediately available. The recommended accepted criteria are shown in Tables 5-1 through 5-4.

A minimum of eight tan δ measurements should be performed at each voltage step during a tan δ test. Careful attention should be paid to the trend of the tan δ values with time, particularly at applied voltages above the normal phase-to-ground operating voltage. Significant increases and decreases in tan δ with increasing voltage and/or instability during a voltage step are indicative of deterioration in the insulation or accessories. Poor grounding and/or significant corrosion of the ground shield of the cable will also contribute to elevating the tan δ values.

Combined Assessment Criteria

Tables 5-1 through 5-4 give ranges of "good," "further study required," and "action required." Assessment analysis requires consideration of tan δ, delta tan δ, **and** percent standard deviation in tan δ. If any of these are in either "further study required" or "action required," the more stringent range applies to the circuit. A significant increase or decrease in tan δ value as the voltage is increased during the test indicates that the leakage current through the insulation is changing. An increase in leakage current with increasing voltage indicates that the material is discharging at higher voltages and is not stable. A decrease in tan δ or a tan δ that alternately increases and decreases with increasing test voltage is unusual and indicates either a problem with the test process or a significant problem with the cable that should be evaluated further. An elevated percent standard deviation could be caused by partial discharging or tracking in or around a defect site or at a degraded splice or termination. Very high tan δ measurements indicate large leakage currents and could be indicative of many water-related degradation sites or a smaller number of highly deteriorated sites. The analysis performed in report 1025262 [26] indicates that there is often correlation between the three criteria. However, in some cases, a single attribute was unacceptable and correctly identified a degraded condition in a cable.

Anecdotal information indicates that deteriorated cables that had been installed before the mid-1970s tend to have many degradation sites and that cables manufactured later will fail less frequently, but if they do, they will fail from a single large manufacturing flaw (that is, manufacturing and design improvements reduced the likelihood of overall insulation degradation from wet conditions, but occasional significant manufacturing flaws still occur). Accordingly, for very early cables, elevated tan δ may be a strong indication of degradation, but for later cables, the differential value between 0.5 V_0 and 1.5 V_0 is likely to be a better indicator. The criteria provided in Tables 5-1 through 5-4 are based on data from research and in-plant testing. The values have been chosen to identify the degradation of concern. The criteria for "action required" were chosen to be conservative and have been proven via analysis of nuclear industry data [26].

Table 5-1
Tan δ assessment criteria for XLPE (in terms of x 10^{-3}; 0.1 Hz test frequency)

Condition	Tan δ		Absolute Value of the Difference in Tan δ Between 0.5 V_0 and 1.5 V_0 (1, 2)		Percent Standard Deviation of Tan δ Measurements at Any Step of Test Voltage
Good	≤1.2	and	≤ 0.6	and	≤0.02
Further study required	>1.2, ≤ 2.2	or	>0.6, ≤ 1.0	or	>0.02, ≤0.04
Action required	>2.2	or	>1.0	or	>0.04

Notes for Table 5-1:
1. Differentials may be taken at 1 V_0 and 2 V_0 at the user's option. See the text preceding this table.
2. The difference in tan δ is normally positive. Negative differences should be treated as very significant and might indicate a problem with a test or the presence of a significant defect.

Table 5-2
Tan δ assessment criteria for butyl rubber and black EPR (in terms of x 10^{-3}; 0.1 Hz test frequency)(1)

Condition	Tan δ		Absolute Value of the Difference in Tan δ Between 0.5 V_0 and 1.5 V_0 (2, 3)		Percent Standard Deviation of Tan δ Measurements at Any Step of Test Voltage
Good	≤12	and	≤3	and	≤0.02
Further study required	>12, ≤ 50	or	>3, ≤ 10	or	>0.02, ≤0.04
Action required	>50	or	>10	or	>0.04

Notes for Table 5-2:
1. This is based on the analysis performed in EPRI Report 1025262 [26].
2. Differentials may be taken at 1 V_0 and 2 V_0 at the user's option. See the text preceding these tables.
3. The difference in tan δ is normally positive. Negative differences should be treated as very significant and might indicate a problem with a test or the presence of a significant defect.

Table 5-3
Tan δ assessment criteria for pink EPR[1] (in terms of x 10^{-3}; 0.1 Hz test frequency)[2]

Condition	Tan δ		Absolute Value of the Difference in Tan δ Between 0.5 V_0 and 1.5 V_0 [3, 4]		Percent Standard Deviation of Tan δ Measurements at Any Step of Test Voltage
Good	≤15	and	≤3	and	≤0.02
Further study required	>15, ≤30	or	>3, ≤8	or	>0.02, ≤0.04
Action required	>30	or	>8	or	>0.04

Notes for Table 5-3:
1. This may also be used for "Gray" UniBlend EPR. (The approximate time of manufacture is from the late 1970s on.)
2. This is based on analysis performed in EPRI report 1025262 [26]
3. Differentials may be taken at 1 V_0 and 2 V_0 at the user's option. See the text preceding these tables.
4. The difference in tan δ is normally positive. Negative differences should be treated as very significant and might indicate a problem with a test or the presence of a significant defect.

Table 5-4
Tan δ assessment criteria for brown EPR (in terms of x 10^{-3}; 0.1 Hz test frequency)[1]

Condition	Tan δ		Absolute Value of the Difference in Tan δ Between 0.5 V_0 and 1.5 V_0 [2, 3]		Percent Standard Deviation of Tan δ Measurements at Any Step of Test Voltage
Good	≤50	and	≤5	and	≤0.02
Further study required	50, ≤60	or	>5, ≤15	or	>0.02, ≤0.04
Action required	>60	or	>15	or	>0.04

Notes for Table 5-4:
1. This is based on Figures C-3 and C-4 in EPRI report 1021070 [16] and consultation with tan δ testers.
2. Differentials may be taken at 1 V_0 and 2 V_0 at the user's option. See the text preceding these tables.
3. The difference in tan δ is normally positive. Negative differences should be treated as very significant and might indicate a problem with a test or the presence of a significant defect.

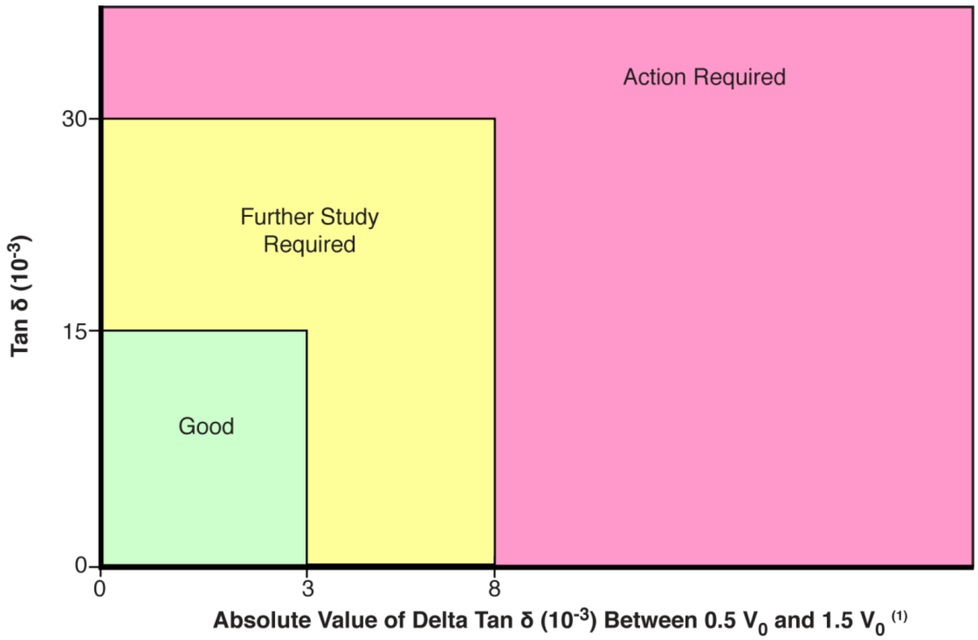
Recommended Considerations for Cables Exceeding the "Good" Range

Based on currently available operating experience, the onset of degradation for cables that have successfully passed installation testing and initial condition assessment should not occur until the cables are 20–30 years old. Based on this expected age for the onset of degradation, a prudent approach for cables in the scope of the cable aging management program would be to perform testing after they are in service for 10 years, but prior to 20 years of service. Once cables reach the point where they are being monitored under the cable aging management program, they should be retested on a six-year frequency if they continue to test "good."

Cables with results in the "further study required" range should be subjected to more frequent testing (for example, every two years or once per refueling cycle) to determine whether the condition is stable or worsening. Consideration should be given to performing a VLF withstand test should a "further study required" result occur.

While immediate repair or replacement is desirable for a cable with an "action required" result, additional testing could be performed to verify serviceability for a limited period to allow the cable to return to service. Placing cables back in service after passing a withstand test would not preclude an in-service failure, but it would provide some reasonable assurance that the defect is not significant enough to fail in the near term. Decisions on returning degraded cables to service that have passed a withstand test must be also evaluated for the safety and operational effects should a cable fail during operation. Section 7 addresses options for the repair and replacement of cable.

Figure 5-1 provides a pictorial version of the assessment criteria shown in Table 5-3 for pink EPR to help in understanding how the criteria work. The tan δ values are shown on the vertical axis, and the change in tan δ values between the points of 0.5 V_0 and 1.5 V_0 are shown on the horizontal axis. Staying within the limits of the green box for tan δ and delta tan δ means that the cable is in good condition. If the tan δ exceeds 15×10^{-3} but is less than 30×10^{-3}, further assessment is needed. At a minimum, the period between tests should be shortened, and the potential cause of the elevated value sought. Similarly, a delta tan δ greater than 3, whether increasing or decreasing, would be a cause for shortened periods between tests and a review to determine the cause. If the tan δ exceeded 30 or the delta tan δ exceeded 8, action should be taken to repair or replace the cable. An additional axis for percent standard deviation could be added, but that is not shown because the complexity of the figure would be high and lead to confusion.



Note for Figure 5-1
1. The difference in tan δ is normally positive. Negative differences should be treated as very significant and might indicate a problem with a test or the presence of a significant defect.

Figure 5-1
Pictorial representation of tan δ assessment criteria for pink ethylene propylene rubber

Figure 5-2 shows a typical tan δ plot for a shielded EPR-insulated three-phase cable. For each of the three phases, the tan δ is stable through the range of test voltage, showing a very small increase with each step in voltage. The percent standard deviation at each step was very small during the period of voltage application for the step. It should be noted that this test combined VLF tan δ with a VLF withstand test. The last voltage step for this test was at 7 kV, the withstand test value. The duration of the 7-kV step was 30 minutes.

Phase C Summary: 0.1 Hz, 58.1 nF

Voltage [kVrms]	1.2	2.4	4.0	7.0			
TD Value [E-3]	11.5	11.5	11.7	12.0			
Std. Dev. [%]	0.00	0.00	0.00	0.00			

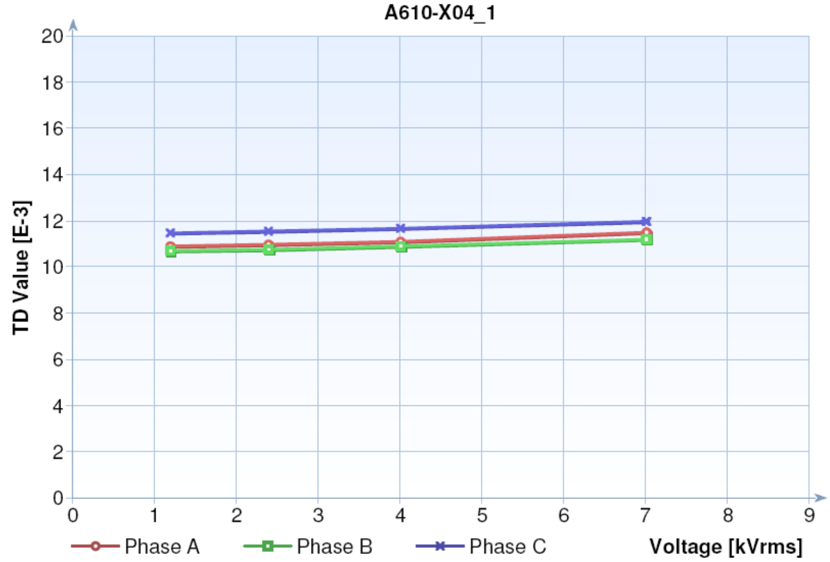


Figure 5-2
Typical "good" tan δ result for a shielded cable with pink ethylene propylene rubber insulation

Figure 5-3 shows a tan δ plot for a UniShield pink EPR cable operated at 13.8 kV with degradation on the B phase. The plots for the A and C phases have acceptable tan δ values that are stable through the four steps in applied voltage and had very small percent standard deviations at each voltage step. The B phase had good measurements at the first two voltage steps, but it began an upward trend at the third step with a very significant increase at the fourth step. The tip up at higher voltage indicates instability in the insulation that indicates a weakness requiring further study.

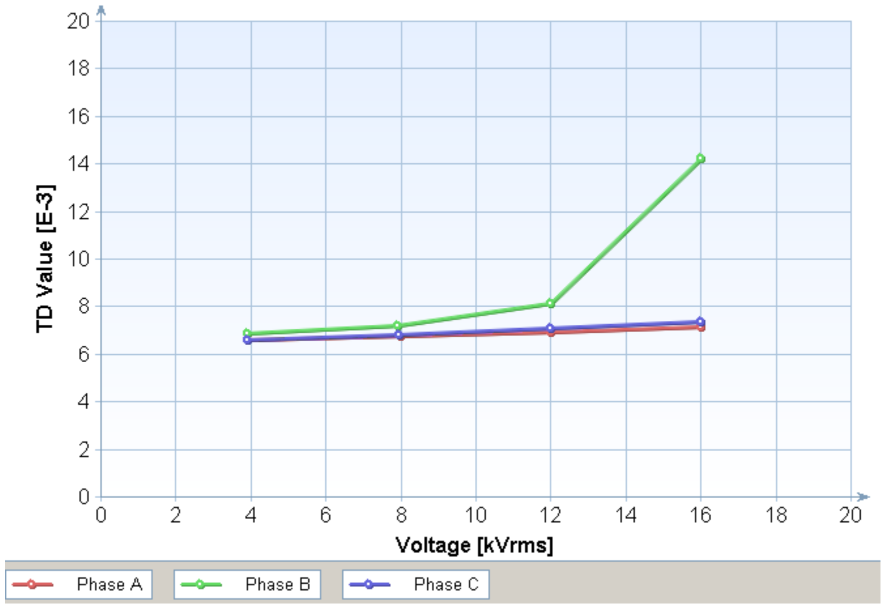


Figure 5-3
Tan δ plots for a 13.8-kV UniShield cable with a degraded B phase

Figure 5-4 provides an example of a case in which a 15-kV cable was subjected to tan δ testing. Had the test been stopped at V_0 (8 kV) and only the absolute value of tan δ and delta tan δ considered, all three phases of the cable would have been deemed acceptable. However, evaluation of the percent standard deviation at 8 kV finds the B phase acceptable, a small shift for the A phase (0.01), and a higher level for the C phase (0.02). Evaluation of the test at 1.5 V_0 shows that all figures of merit indicate that problems exist for both the A and C phases; at 2 V_0, the evaluation shows that the cable is highly degraded. At the higher voltages, the percent standard deviation is extremely high in comparison to the assessment criteria. In this case, the C phase cable failed after 30 seconds at 2 V_0, indicating that percent standard deviation as well as absolute tan δ and delta tan δ were strong indicators of deterioration of the C phase cable insulation. The B phase had acceptable tan δ, delta tan δ, and percent standard deviation values through all test voltages.

Phase A Summary: 0.1 Hz, 331.6 nF

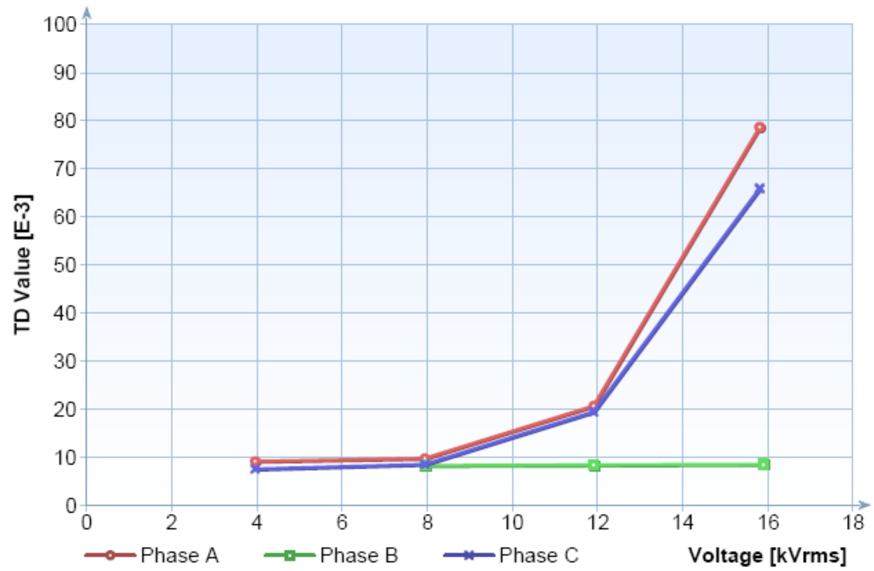
Voltage [kVrms]	4.0	8.0	11.9	15.8			
TD Value [E-3]	9.1	9.8	20.6	78.7			
Std. Dev. [%]	0.00	0.01	0.25	0.98			

Phase B Summary: 0.1 Hz, 330.1 nF

Voltage [kVrms]	7.9	11.9	15.9				
TD Value [E-3]	8.2	8.3	8.5				
Std. Dev. [%]	0.00	0.00	0.00				

Phase C Summary: 0.1 Hz, 330.5 nF

Voltage [kVrms]	4.0	7.9	11.9	15.8			
TD Value [E-3]	7.5	8.5	19.4	65.9			
Std. Dev. [%]	0.00	0.02	0.23	0.45			



Std. Dev. = Standard Deviation

Figure 5-4
Tan δ example including percent standard deviation data

Very Low Frequency Withstand Testing in Conjunction with Tan δ Testing

VLF withstand testing may be performed in conjunction with tan δ testing as described previously. If single severe local degradations are present, the VLF withstand test is designed to cause them to fail at the time of the test.

If a cable has indications that it is degraded based on tan δ results, a VLF withstand test could be used to determine whether the cable has localized highly degraded segments (that is, it fails the withstand test) or lesser, more distributed degradation (that is, it passes the withstand test). If the cable passed the test, there is a reasonable likelihood that it will function until a more convenient time for repair or replacement of the cable.

The methodology for VLF withstand testing, including discussions of test voltages and durations, are contained in IEEE Std. 400.2 [13]. The assessment criterion is simple. If the cable does not fail during the test, it is judged adequate for continued use.

An improvement to a standard VLF withstand testing is to monitor tan δ for stability during the withstand test. While the withstand test is a go-no-go test, there is value in evaluating the magnitude and percent standard deviation for this portion of the test. If the magnitude is excessive or unstable (continuously increasing over the hold time) or if the percent standard deviation exceeds the assessment limits, then this information should be used in the overall evaluation of the cable condition. A successful withstand test with a stable tan δ indicates that there are no large local defects and that no defects are in the process of breaking down. Unstable tan δ during the withstand test likely indicates that a significant degradation site exists and that it may be in the process of going to failure.

Test Methodology and Assessment Criteria for Other Tests

Descriptions of off-line dielectric spectroscopy and partial discharge testing are beyond the scope of this report. When such tests are used to assess the condition of cable, the testers and interpreters of the test data must have the requisite skills and related experience to apply the test and to perform the interpretation of the results. Experience with the specific cable type (insulation and design) is recommended. EPRI report *Medium-Voltage Cable Aging Management Guide, Revision 1* (1021070) provides additional information on these testing techniques [16].

Test Preparation and Concerns

To allow testing of cable circuits with either off-line partial discharge testing, tan δ, or withstand testing, the connected load (for example, a transformer, motor drive, or motor) must be disconnected and the terminations isolated. All surge and lightning arrestors and voltage transducers must also be disconnected from the circuit under test. In some cases, testing may be performed through the backplane of the associated breaker cubicle, but before this is attempted, it is recommended that initial testing be performed with a cable connected to and then isolated from the cubicle to determine the effect of the cubicle backplane. If there is a significant influence from the breaker backplane, the cables should be disconnected from the breaker backplane. Testing of XLPE cables is likely to require separation of the cable from the breaker backplane to reduce inaccuracies.

Testing must be performed with a prepared termination at each end of the cable to control voltage stresses. For 4.16–6.9 kV applications, removal of the metal shield and insulation semiconducting layer in preparation for the installation of a termination will suffice to allow testing to 2 V_0. However, the length of insulation after removal of the semiconducting layer will be too short when a splice is being prepared, and stress control will be necessary. Testing of 12 kV and higher circuits will require stress control to prevent flashover. Under no circumstance should testing be performed with the insulation shield in place to the end of the insulation at either end of the circuit; doing so will cause a flashover. Suitable stress cones must be used at each termination. The cable's metallic shield must remain grounded during testing. In addition, before testing, terminations should be inspected for cleanliness and general condition. Cleaning and/or repair may be necessary before cable testing occurs. In addition, the terminations must be located well away from the terminations of adjacent phases and the termination cabinet/box to reduce corona effects during the test. In confined spaces, use of insulating sheets (for example, Mylar) may help to ensure adequate separation between phases and from phase to ground.

In tan δ testing, cables of different types (for example, XLPE, butyl rubber, and EPR) should be tested separately if they are spliced together; otherwise, the material with higher losses will mask problems in the less lossy material. For example, severe deterioration in XLPE would likely be masked by the natural lossy characteristic of EPR or butyl rubber, and butyl rubber could mask problems in EPR. In addition, if splices are used in circuits that have the same cable materials, nonlinearity of the insulation resistance of some splice types may cause abnormal tan δ results that are not indicative of the condition of the cable insulation (see EPRI report *Medium-Voltage Cable Aging Management Guide, Revision 1* [1021070] Appendix C) [16].

When cables with multiple conductors per phase are being tested, tan δ testing of the individual conductors in each phase will provide the best results. It is understood that separating the conductors can be difficult and time consuming. If the insulations of each of the conductors deteriorated simultaneously, the tan δ measurement of the joined conductors would obviously indicate insulation condition. However, if the insulation of only one conductor of a multi-conductor per phase circuit were deteriorated, testing of the joined set could mask the deterioration. In effect, multiple conductors with good insulation mask a single defect or small section of degraded cable. The "averaging" of the good-to-deteriorated sections is stronger because the number of conductors in parallel or the overall circuit length increases. Accordingly, if joined-set testing is being performed, careful scrutiny of the results is recommended to determine whether further testing of the separate cables is warranted.

Regarding testing of motor and transformer circuits, if tests are to be performed periodically, separable connectors and disconnects should be considered so that the motor connections can be easily broken and remade. Use of separable disconnects will be advantageous to the testing of the motor or transformer and the cable. (Note: As of this writing, separable connectors that have a manufacturer's environmental qualification do not exist.) Motor testing frequently entails the use of high-voltage dc, which is not recommended for cables because it has been linked to damage of the cables' extruded polymer insulation. Separation of the motor from the cables is recommended when dc or surge testing is performed on the motor. Testing of cables with off-line ac tests would provide no useful information about the cable if the motor remained connected to the cable.

Failure of Cable Under Test

Concern exists that a “good” cable may fail under a test using elevated voltage. The tests recommended here have elevated rms test voltages of 1.5–2 times the line-to-ground voltage in accordance with IEEE Std 400.2 [13]. These ac tests are performed with either line frequency (for example, 60 Hz) or VLF (for example, 0.1 Hz).

Figure 5-5 shows that the insulation of a new cable can withstand a short period of >30 times the line-to-ground voltage or more before breaking down. Figure 5-5 also indicates that severely degraded cables that were tested during forensic evaluation in the laboratory have short duration ac breakdown strengths greater than 4 V/V_0 (V is applied voltage, V_0 is operating voltage, line-to-ground). Based on these data, cable insulation that cannot withstand only twice the line-to-ground voltage for the duration of an off-line test is highly degraded and prior to the test was not in a condition considered satisfactory for long-term reliable service.

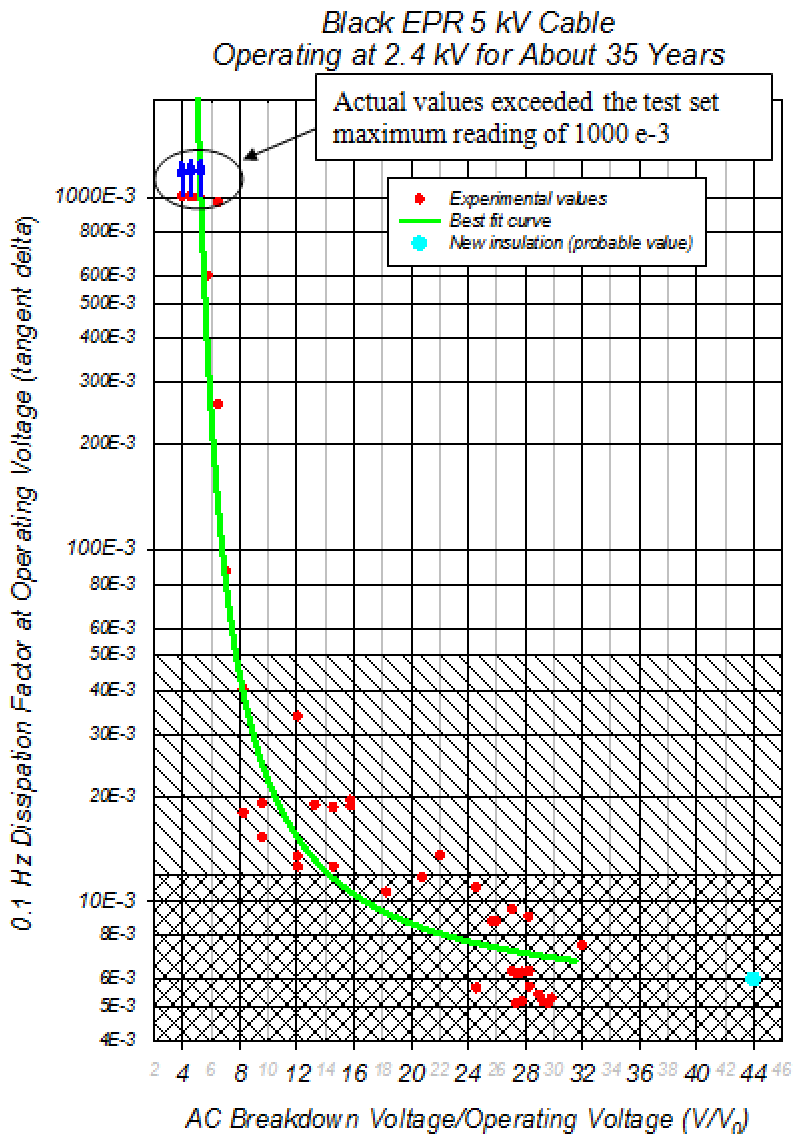


Figure 5-5
Graph showing the inverse relationship of ac breakdown to 0.1-Hz tan δ magnitudes for service-aged cables in wet environments. The blue data point is the expected ac breakdown strength of a new cable

When performing tan δ or partial discharge testing, test operators can generally identify when cables have inadequate insulation properties and can stop testing before failure. Occasionally, a failure will occur during a test. In these cases, the cable failed because it was degraded, not because the test caused rapid deterioration. Ac withstand tests can be used to cause weakened cable to purposely fail by applying elevated voltage for an extended period. The utility and cable testing industry continue to refine withstand testing methodology to ensure that significant degradations are brought to failure during testing and that lesser degradation is not aggravated so that failure occurs shortly after return to service.

Dc withstand testing is not recommended. Although it was effective for evaluating paper-insulated lead-covered cables, it has been found on some cable designs to worsen end-of-life degradation of polymer insulations, but not necessarily to cause cable failure at the time of testing. The cables fail in dc withstand testing only if they are very severely aged. Under conditions in which the cable is slightly less aged, the application of a dc test can cause an existing flaw to convert to electrical discharge so that the cable fails a short period after the return to service [17]. Because passing a dc withstand test may cause a false sense of security and because the dc testing may shorten the remaining limited life, dc withstand testing is not recommended for the purposes of ensuring continued functionality of polymer-insulated cable.

Insulation Resistance Measurement and Acceptance Criteria

Confusion exists on when insulation resistance is useful for aging management and what acceptance criteria should be used.

Many plants use 1 megohm plus 1 megohm per kV of applied voltage as the criteria for acceptance of cables for return to service. ***This value is wrong, and it is unacceptable as a basis for returning any cable to service.*** The value is taken from the 1974 version of IEEE Std. 43 for rotating electrical equipment [28]. The value applied to motors with winding systems that pre-date 1970 that were relatively porous and could have very low insulation resistances when damp. The acceptance value was related to whether it was safe to test the winding at elevated voltages and was never meant to be used as a cable condition acceptance criterion. It should be noted that IEEE Std. 43-2000 requires a 100-megohms level for modern form-wound motor insulation systems.

There are two problems with the 1 megohm plus 1 megohm per kV approach: First, the value is much too low and represents essentially failed cable insulation; second, it does not account for cable length. Insulation resistance of cable insulation is inversely proportional to length. A low insulation resistance in a short length of cable is much worse than a low insulation in a long length. Common practice is to provide insulation resistance in terms of 1000 ft or 1 km lengths. The reading is multiplied by the length divided by 1000 ft or 1 km to give the corrected value to compare to the acceptance criteria.

New cable insulation, whether low or medium voltage, has an insulation resistance of multiples of gigohms per 1000 ft (305 gigohms per km). Therefore, if the insulation resistance is only 100 megohms per 1000 ft (30.5 megohms per km), a dramatic decrease in insulation resistance has occurred. Something is wrong with the insulation of the cable that needs to be understood. To determine the insulation resistance of the cable, it must be disconnected from the associated end device such as a motor or transformer. Given that plant owners are reluctant to disconnect a motor and reconnect it for testing a cable, there are two options:

- Install separable disconnects such as gel-based splices that reduce the time, effort, and likelihood of error when testing the motor and cable separately is desirable.
- Adopt 100 megohms as the combined insulation resistance where separation of the motor and cable must be performed to determine whether the motor or the cable is the source of low insulation resistance. This is based on 100 megohms per 1000 ft (30.5 megohms per km) as the minimum acceptable insulation resistance for cable.

Separating the motor from the cable for motor testing will provide better results for the motor and is highly recommended if motor surge tests are to be performed. If a motor surge test is performed through the cable, the motor is not being tested properly because the capacitance of the cable will absorb most of the surge voltage before it reaches the motor terminations. When the motor is separated from its cable, insulation testing (tan δ testing for medium-voltage cables) should be performed.

Insulation resistance is a valuable troubleshooting test, but it has limited value as a condition monitoring test for medium-voltage cables. Table 5-5 summarizes when and how insulation-resistance testing can be of value. Insulation resistance is not recommended as the main means of assessing shielded medium-voltage cable insulation. It can identify severely degraded insulation that is in the nearly failed state, but it is not expected to detect the light-to-very-severe conditions that can be detected by tan δ and dielectric spectroscopy testing. In other words, insulation resistance is likely to give little warning of the onset of severe aging in medium-voltage cables and, in many cases, may erroneously indicate that the insulation is satisfactory for long-term service. For non-shielded cables, insulation-resistance testing is essentially testing with respect to the contact point between adjacent phases and from phase to random grounds. The results are nearly useless. The only exception is for testing wet non-shielded medium-voltage cable. In this case, a bad test result would have to be believed, but an "acceptable" value (gigohms) would not provide confidence that the circuit is or is not in good condition. The result would be better than no data, but it would not be an absolute indication of acceptability.

Table 5-5
Applicability of insulation resistance testing to cable aging management

Cable Type and Environment	Condition Monitoring Discussion	Troubleshooting Discussion
Medium-voltage shielded cable – dry environment	Dry insulation will have high insulation resistance whether thermally aged or not. No useful trending data would be expected.	Insulation resistance is useful for troubleshooting failed circuits and can identify the phase that has failed.
Medium-voltage shielded cable – wet environment	If an insulation resistance test is performed and the result does not meet 100 megohms per 1000 ft (30.5 megohms per km), the phase is severely degraded and should either be replaced or tested with an off-line elevated voltage test such as tan δ to determine its condition accurately. Values of a gigohm or more do <u>not</u> indicate that insulation is in satisfactory condition. Only off-line elevated voltage tests can truly indicate insulation condition.	Insulation resistance is useful for troubleshooting failed circuits and can identify the phase that has failed. Values as high as tens of megohms can occur even on a failed phase because faults often blow out the shield, leaving a long surface resistance between the conductor and the remainder of the shield system.
Medium-voltage, non-shielded cable – dry environment	Dry insulation will have high insulation resistance, whether thermally aged or not. No useful trending data would be expected. The lack of a ground plane for testing compounds the problem.	If a fault occurs and the ground remains electrically close, such as a carbon path and not dry air, to the conductor, insulation-resistance testing might be useful.
Medium-voltage, non-shielded cable – wet environment	Insulation-resistance testing will not produce useful data for trending, but it might provide some indication of the existence of severe degradation under the premise that some information is better than none.	If a fault occurs and the ground remains electrically close, insulation-resistance testing might be useful.

Insulation-resistance testing is not recommended as a condition-monitoring technique for cables under most conditions, with the exception of wet low-voltage cable. However, if a value of less than 100 megohms per 1000 ft (30.5 megohms per km) is measured on medium-voltage cable between the shield and the conductor, it is a strong indication that the insulation is flawed, deteriorated, or failed, and the cause of the low measurement should be investigated and dispositioned. Insulation resistance of a cable must be adjusted for the circuit length to be of any practical use. Insulation resistance is a valuable troubleshooting tool when cable insulation failure has occurred.

Assessment of Non-Shielded Cables

Non-shielded cables, those cables without an insulation shield, represent a significant problem regarding off-line electrical testing. To allow an electrical test of the insulation, a uniform ground plane is needed, but such a ground plane does not exist in a non-shielded cable. Testing of non-shielded cable from phase to ground may provide only rough data at the random grounding points along the surface of the cable. Testing phase to phase may provide only information concerning the points where the phases touch one another. (Better results could be expected from a test of a triplexed cable than from three separate cables pulled together.) This limitation could cause variable results if water levels vary and make trending and assessment of results difficult. One way to produce a ground plane would be to fully flood the ducts and verify that the water was grounded. Surrounding the cable with water is used in laboratory assessments, but it has not been attempted in a power plant.

Given that off-line electrical testing of non-shielded cables is not practical, other alternatives must be selected, which are the following:

- Conducting a full forensic analysis of cables if failure occurs
- Applying lessons learned from operating experience from related cables under similar conditions
- Applying lessons learned from the forensic analysis of shielded cables with the same insulations from other plants
- Removing and testing abandoned non-shielded cable
- Removing and testing cable removed from service

The non-shielded cables in use in the nuclear industry almost always have EPR insulation and are limited to those rated 5 kV. The insulations are the same types that were used in shielded cables. The differences for the shielded cables are the absence of the insulation shield and a somewhat thicker insulation on the non-shielded cables.

A review of installed non-shielded cable data from the NEI 2005 industry survey [17] indicates that 31 of the responding units had some non-shielded medium-voltage circuits. The dominant manufacturers were Kerite and Okonite, with one plant reporting General Cable and another reporting Anaconda. Kerite has used brown EPR throughout the period, whereas Okonite used black EPR through the mid-1970s and then switched to pink EPR thereafter. Review of the failures of nuclear plant cables revealed only three failures. Only one failure report directly stated that wetting of the cable was involved and also indicated that thermal overload contributed to the degradation.

Although these data do not eliminate wet aging as a concern, they indicate that the lack of a shield on these cables does not lead to more frequent failure than for shielded cables.

Removal of abandoned cables that have experienced long service under wet conditions is a valuable input to understanding the degree of electrically induced wet aging that can occur. Currently, two sets of Kerite cables that experienced 30 years of service before being abandoned are being evaluated by EPRI. Laboratory testing of these cables will give insights regarding wet degradation of non-shielded cables. The laboratory analysis may also give insights as to whether in-service electrical testing is practicable (that is, using water as a ground shield).

For plants with non-shielded cables, the recommended path is as follows:

1. Require full forensics testing of any failure of non-shielded medium-voltage cable, with appropriate action taken for other non-shielded cables in similar operating conditions (for example, if failures are wet aging related, replace similar circuits).
2. Maintain an awareness of the results of research performed on abandoned cables or those removed from service.
3. Maintain an awareness of the results of failure assessment and mechanism research for related shielded medium-voltage cable. For example, findings on the same manufacturer's material (for example, black, brown, or pink EPR) from a shielded cable may give insights on the expected aging of a non-shielded cable.
4. Carefully assess the operating experience for non-shielded cables of the same type and material for applicability and any indication of additional concern.
5. When industry insights indicate that non-shielded wetted cable may be entering an end-of-life state, either remove a "worst case" cable from service and perform laboratory testing or schedule the replacement of wetted circuits.

Section 6: Actions for Cables with Dry Adverse Environments

Program Element 6

When the review of medium-voltage cables circuits within the scope of the program determines that cables are subject to dry adverse localized environments, actions should be taken to determine the effect on the condition of the cables.

When hot process equipment is sufficiently close that medium-voltage cable could be affected by thermal damage, visual assessment of the condition of the cable should be performed, and appropriate actions taken based on the identified condition. Physical and chemical tests of the insulation system can be performed to further define the condition and the need to repair or replace the cable circuit. As applicable, the source of the thermal damage should be mitigated, or rerouting of the cable should be considered.

For circuits in which elevated conductor temperature from operating currents is determined to be a concern, visual assessment of the condition of the cable should be performed and documented, and appropriate actions taken based on the identified condition. Physical and chemical tests of the jacket and/or insulation system can be performed to further define the condition and the need to repair or replace the cable circuit.

When inspection or infrared thermography indicates that connections are overheating, the degree of damage should be assessed, and the connection repaired or replaced as appropriate.

The effects of adverse dry environment conditions will be different from those caused by cables being energized in wet or submerged conditions because the failure mechanisms are not the same. Accordingly, different assessment methods apply. This section addresses the assessments that can be applied to cables in dry adverse environments.

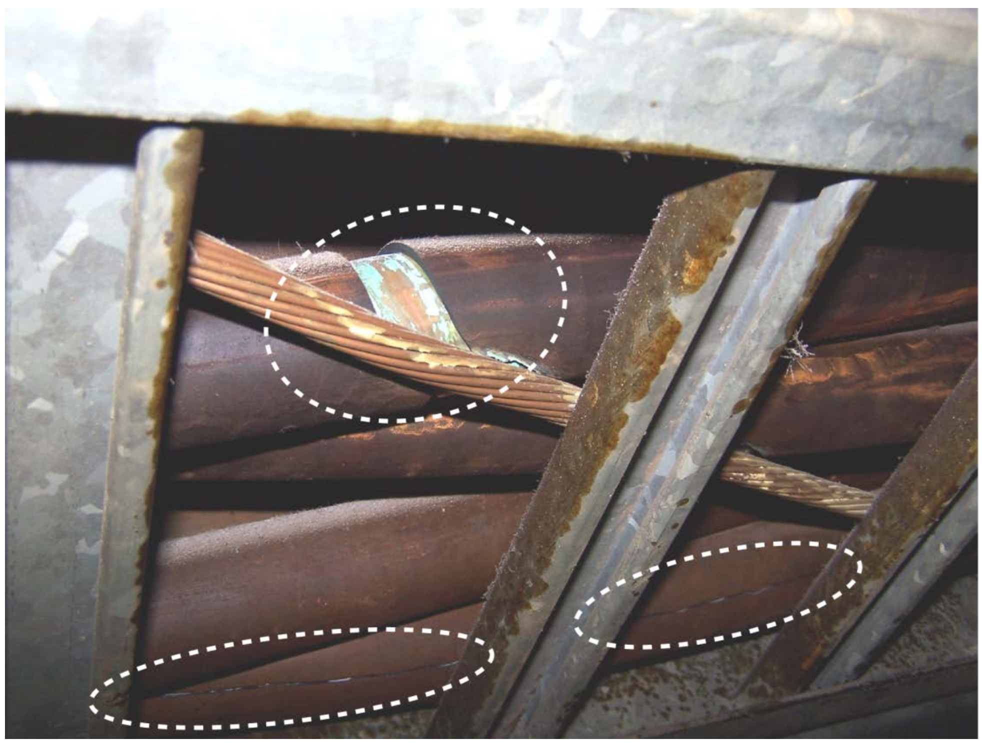
High-Temperature or High-Dose-Rate Ambient Environments

Different aging effects in dry environments can occur, depending on the insulation type and jacket type in use. Table 6-1 describes the degradation mechanisms that are expected for common types of medium-voltage cable jackets.

Table 6-1
Thermal and radiation degradation mechanisms expected for medium-voltage cable jacket materials

Material	Temperature-Induced Degradation	Radiation-Induced Degradation	Condition Evaluation	Effect of Degradation
Neoprene	Hardening with spontaneous cracking and discoloration (turning greenish-brown)	Hardening	Visual inspection can identify discoloration or cracking. Hardening can be manually or indenter evaluated with the cable de-energized.	Cracking exposes the shield and insulation to airborne moisture. Released chlorine will corrode the shield and cause limited effects on insulation. Loss of the jacket will adversely affect flame propagation.
Hypalon (chlorosulfonated polyethylene [CSPE])	Hardening and discoloration (turning greenish-brown)	Hardening	Visual inspection can identify discoloration. Hardening can be manually or indenter evaluated with the cable de-energized.	Until extreme hardening occurs, Hypalon will remain intact. However, if a through fault occurs, the cable may crack because of motion from high magnetic fields.
Polyvinyl chloride (PVC)	Hardening, possible spontaneous cracking	Production of hydrogen chloride (HCl)	With the cable de-energized, hardening can be observed manually or through the indenter. HCl production may be indicated by white powdering or corrosion of surrounding metal.	Cracking exposes the shield and insulation to airborne moisture. Released chlorine will corrode the shield, causing limited effects on the insulation.
Chlorinated polyethylene (CPE)	Hardening, cracking (thermoplastic only)	Hardening	With the cable de-energized, hardening can be observed manually or through the indenter.	Extreme hardening may cause failure. Cracking of thermoplastic versions would be expected with significant thermal aging.

In the case of thermal damage from the environment rather than from ohmic heating, the jacket will deteriorate before the insulation system. If the damage is from the environment, the deterioration of PVC and neoprene is likely to be of most concern because these jackets tend to crack spontaneously on severe aging. Figure 6-1 shows cracking of a neoprene jacket from an elevated thermal environment. One concern for both neoprene and PVC when highly thermally aged is that they will generate chlorine, which will affect the shield and surrounding metal materials, such as trays, conduits, and possibly piping. Under dry conditions, environmentally induced deterioration of PVC or neoprene might not cause an immediate concern for the aging of the insulation because the insulation will tend to age more slowly. Hypalon will age more slowly than neoprene and early PVCs and will have a much lower tendency to crack spontaneously. Early thermoplastic chlorinated polyethylene (CPE) can crack when it ages and if highly stressed (for example, at bends). Modern thermoset CPE will not tend to crack with aging. If Hypalon and modern thermoset CPE are found to be aged, there is a higher likelihood of thermal damage to the insulation, but again, the insulation should age more slowly than the jacket from environmentally induced aging.



Note: Corrosion of tray and shield are likely from chlorine released by the aging of the neoprene. The jacket has turned brown from the original black and is very hard. The brown color of the jacket is a strong indication of exposure to elevated temperature.

Figure 6-1
Spontaneous cracking of a neoprene jacket

Depending on the application and the severity of the cable jacket cracking, different actions may be warranted. Jackets are important to keep moisture out of cables and to prevent fire propagation. If medium-voltage cables require environmental qualification for steam accident, cracking in a location with a potential steam environment would be unacceptable without further assessment. All cables are required to limit flame propagation; therefore, if cracking is severe enough that the jacket is in danger of falling off or has already done so, the flame retardancy provided by the jacket has been lost, and corrective action is needed. For shielded cable, loss of jacket integrity could allow additional grounding points on the shield. Only a few plants have safety-related medium-voltage cables within containment. Accordingly, very few plants take credit for medium-voltage cable jackets acting as beta shields. Severe cracking of jackets on medium-voltage cable within containment could add to sump loadings in the event of an accident.

Severe jacket aging indicates that insulation damage may have occurred as well and that electrical assessment of the cable, as indicated for insulation damage in Table 6-2, should be implemented.

A tan δ or partial discharge test, as appropriate to the concern, will indicate whether the thermal damage has been severe enough to adversely affect the insulation properties. These tests can be performed only on shielded cables.

Line resonance analysis (LIRA) can be used on shielded and non-shielded triplexed cable to detect the effects of localized thermal damage. For shielded cables, it assesses only the insulation system. For triplexed cable, the jackets are included in the assessed material. If LIRA does not produce a signal at the site of the adverse localized thermal environment, the damage is not significant. If LIRA does produce a signal, the strength of the signal is proportional to the severity of the damage, and a relative effect could be determined. LIRA is not useful on non-shielded cables that are pulled individually rather than triplexed. LIRA requires a uniform geometry along the length of cable under assessment. It should also be recognized that if the elevated temperature condition exists at the time of testing, LIRA is likely to identify the effects of the elevated temperature and not necessarily identify thermal damage. (Thermal expansion of the cable in the heat-affected zone can cause a LIRA signal.) Accordingly, LIRA testing should be performed when the localized heat source is not producing heat.

Table 6-2
Thermal and radiation degradation mechanisms expected for medium-voltage cable insulation materials

Material	Temperature-Induced Degradation	Radiation-Induced Degradation	Condition Evaluation	Effect of Degradation
XLPE	Hardening	Hardening	Electrical tests are required to determine whether leakage current is increasing because of damage. LIRA testing would identify whether thermal damage has occurred. Consider tan δ measurement to determine whether the cable's insulating capability has been adversely affected.[1]	Ultimately, insulation could crack (after a very long time). The cable's life could still be long if the condition is corrected before severe degradation occurs.
Butyl rubber	Hardening or softening	Softening	Electrical tests are required to determine whether leakage current is increasing because of damage. LIRA testing would identify whether thermal damage or compression of softened insulation has occurred. Consider tan δ measurement. If softening has occurred, partial discharge may occur if components drift with respect to their original position.	Softening failures have occurred on sulfur-cured butyl rubber insulation from advanced thermal aging. The shield drifted through the softened insulation toward the conductor, leading to failure.
EPR	Hardening	Hardening	Electrical tests are required to determine whether leakage current is increasing because of damage. LIRA testing would identify whether thermal damage had occurred. Consider tan δ measurement to determine whether the cable's insulating capability has been adversely affected.[1]	Extreme thermal aging has caused failure (embrittlement or thermal runaway).

Note for Table 6-2:
1. Early polymeric shields may be more age sensitive than modern extruded shields. If they crack, partial discharge would be expected, and partial discharge testing may be a useful test method.

Table 6-2 describes the degradation mechanisms that are expected for common types of medium-voltage cable insulations. The various insulation types behave differently from one another. Butyl rubbers that have been cured using sulfur will soften, rather than harden, to the point where the shield can drift toward the conductor,[18] causing very high electrical stress and subsequent insulation failure. EPRs and XLPEs will harden under elevated temperature and dose conditions. The likelihood is that any of these conditions will eventually cause leakage current to increase. Accordingly, tan δ measurement should be a useful assessment method for thermally damaged cable. However, a very localized effect may be difficult to detect with tan δ. Damage affecting a significant portion of the cable run will be more easily identified. An exception to the use of tan δ as the preferred diagnostic tool is that if the components shift when sulfur-cured butyl rubber softens with severe thermal aging, discharging in any gaps that may occur would allow partial discharge testing to be a method of assessment as well. High-intensity partial discharging, even if of low amplitude, will add to the dielectric loss of the insulation and will be detected, but not located, by a tan δ measurement.

For cables produced from the late 1970s forward, the thermal aging rate of polymer shields should be approximately the same as the insulation. However, early polymer shields from the early 1970s may age more rapidly than the insulation. Cables with early polymer shield designs may be more age sensitive than the later vintage cables when exposed to elevated temperature. If cracking occurred within the insulation or conductor extruded shield, partial discharge would be expected.

High Conductor Temperature from Ohmic Heating

Depending on the severity of the ohmic heating, the insulation may be damaged, and the jacket may or may not be damaged. If the jacket is found to be discolored and/or cracked and the environmental conditions are not severe enough to have caused the damage, ohmic heating is likely the cause, and the insulation is likely to have suffered significant thermal damage because of the temperature being significantly higher at the conductor than at the exterior surface.

As described previously for ambient-induced damage, tan δ testing is likely to detect the effects of severe thermal degradation, whether caused by unbalanced magnetic circuits in multi-conductor per phase circuits or by high continuous currents. Significant softening of butyl rubber can cause gaps to open and allow the use of partial discharge testing as well.

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[18] To date, drifting of the shield toward the conductor has been noted only for failure from high ohmic heating situations rather than from environmentally induced conditions.

High-Resistance Connections at Terminations or Splices

There are two considerations for thermal heating of connections, terminations, and splices. The first consideration is a difference in temperature between two connections with identical loadings. Guidance exists in various EPRI infrared thermography reports [18, 19, 20], such as that provided in Table 6-3. Any temperature difference above reference (the difference between two similar targets under similar loading) is a concern. Small temperature differences can be risk managed to allow time to make preparations for repairs, but anomalies caused by high-resistance connections do not necessarily increase linearly; therefore, uncertainty always exists in predicting time to failure. Increased monitoring should be performed to the extent that a rate of degradation can be estimated until the condition is repaired. Table 6-3 provides suggested severity ranges for evaluating indoor electrical power connections.

Table 6-3
EPRI-suggested severity ranges for indoor electrical power connections [18]

Status	Range
Advisory	1°F–15°F (0.5°C–8°C) rise above reference
Intermediate	16°F–50°F (9°C–28°C) rise above reference
Serious	51°F–100°F (29°C–56°C) rise above reference
Critical	>100°F (56°C) rise above reference

The second consideration for high-resistance connections is the absolute thermal limitations of the materials involved. If the components of a cable, termination, or splice exceed the limits at which their physical and/or electrical properties are compromised and the immediate or long-term ability to function is compromised, the condition should be evaluated and corrected accordingly.

As described previously, routine thermographic inspections should be performed on all accessible connections, terminations, and splices based on the application and during post-maintenance testing if they have been disturbed.

Section 7: Actions for Failed or Deteriorated Cable

> ***Program Element 7***
>
> The aging management program for medium-voltage cable systems should require that appropriate corrective action be taken if significant aging that results from adverse localized environments is identified or suspected. Those actions may include assessment, testing, repair, or replacement as appropriate. If the investigation of a failure or deterioration indicates a generic degradation mechanism, circuits with similar conditions should be reviewed to determine whether they, too, require 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, extreme hardening or softening of insulation, or a "highly degraded" result from electrical testing indicates an operability concern. However, 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 the insulation and jacket or an electrical test result indicating "further study required" insulation. The following subsections provide insights about verifying the condition and determining the course of further actions. In-service failure of a cable requires an extent of condition assessment for cables subject to like service conditions.

Corrective Actions

The corrective actions to be taken in response to cable degradation depend on the nature of the degradation and whether the degradation is localized or distributed over a significant length of the cable. Actions may be permanent or temporary, based on the nature of the application and the licensing basis. Some possible considerations and resolutions, which are not all inclusive, are described next. Plant-specific and application-specific conditions can dictate different resolution paths.

Cable Test Indicates "Further Study Required" Insulation System

As described in Section 5, the results of tan δ tests can indicate that a cable insulation system has aged but is not yet in a highly deteriorated state. An aged condition indicates a need for heightened awareness.

Eliminate Obvious Problems

Inspect the terminations for accumulated dirt, moisture, and tracking or other surface problems. Clean and repair as needed. In addition, verify that the terminations of the cable under test were well isolated from adjacent phase terminations and the cabinet/termination box to eliminate corona at the termination as a cause of the adverse results. If termination issues appear to be the cause of the questionable results, retest and determine whether the "further study required" indication still persists.

Perform Very Low Frequency Withstand Test

If a VLF withstand test was not part of the testing process, perform a VLF withstand test to confirm that a single severe degradation site is not the cause of the "aged" indication.

Increase Frequency of Testing

Decrease the period between tests to one refueling cycle. Compare test results to determine whether the condition is stable or worsening. If it is worsening significantly (for example, approaching the "action required" state), schedule the cable for replacement at a convenient time.

Prepare Contingency Plan

Although a "further study required" cable is likely to function for a significant period, a contingency plan should be prepared in case of failure. The plan should cover the availability of replacement cables and accessories, pulling procedures, pulling tools, and the required qualifications of craft.

Perform Polymer Injection

Silicone polymer injection has been shown to improve the breakdown strength of cable insulation for an extended period [21]. In the case of butyl rubber that may soften with age (depending on manufacturing cure issues), polymer injection will not correct the softening issue and would not be recommended. If the degraded cable is a UniShield compact design, caution is advised in attempting to rejuvenate the cable. Rejuvenation will not correct loss of adhesion issues between the insulation and the semiconducting insulation shield and jacket, which is a possible cause of the degraded condition.

Begin Replacement Program for Multiple Cables with "Further Study Required" Insulation

If multiple cables within a plant's population of cables have indications of "further study required" insulation, the need to begin an orderly replacement program should be considered.

Cable Test Indicates "Action Required" Insulation System

Eliminate Obvious Problems

Inspect the terminations for accumulated dirt, moisture, and tracking or other surface problems. Clean and repair as needed. Also, verify that the terminations of the cable circuit under test were well isolated from adjacent phase terminations and the cabinet/termination box to eliminate corona at the termination as a cause of the adverse results. If the termination issues appear to be the cause of the questionable results, retest and determine whether the "action required" indication persists.

Perform Very Low Frequency High-Potential Tests

If a VLF withstand test was not part of the testing process, perform a VLF withstand test to determine if the cable's condition is sufficiently stable to allow an interim period of operation. Note: The purpose of a VLF withstand test is to fail a highly weakened cable. If immediate replacement is being performed, there is no need to perform a VLF withstand test. See "Combined Testing" in Section 5 for additional VLF withstand testing concepts and recommendations.

Identify and Replace Degraded Section

The degraded section of cable is likely to be the section with the adverse localized environment (for example, the wetted section). Accordingly, the section with the adverse localized environment can be cut from the section with the benign environment, and retesting of the segments can be performed to identify the deteriorated section. The appropriate sections would be replaced and spliced to the good sections. If the deteriorated section is dry and the metallic shield is not corroded, partial discharge testing may be appropriate to identify the location of the degradation. Note that shielded splice designs should be qualified in accordance with IEEE Std. 404 [23]. (This standard does not apply to non-shielded designs.) When splicing dissimilar cable types, the use of separable connectors should be considered to allow isolating dissimilar cables for ease of future testing. In no case should a splice be pulled into an inaccessible location (that is, a duct or conduit). Utility-specific limitations on the location of splices should be observed.

Conduct Forensic Testing of "Action Required" Cable

Forensic testing of the "action required" cable segment is recommended to gain insight into the nature of the degradation and whether it is related to the adverse environment or another cause. The forensic information will provide insights into the overall effects of adverse environment aging on the cable system and the potential extent of the condition.

Use Impervious Cable for Wetted Environments

If the cable degradation is related to a wetted environment and long-term wetting cannot be eliminated, consideration should be given to using an impervious cable design for the replacement cable. Impervious cable designs incorporate a lead sheath or a longitudinally corrugated copper sheath that provides a barrier against water ingress.

Cables Experiencing Localized Thermal Damage

Two concerns exist for localized thermal damage. The first is that the temperature of the insulation is so high as to cause the insulation system to fail because of 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 the insulation breaks down through thermal avalanche. This is not an aging phenomenon, but it is a direct effect of excessive temperature. The aging concern is that the temperature 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.

Evaluate the Degree of Damage

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

Evaluation of the severity of the jacket degradation may be performed through indenter modulus assessment [24]. 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.

The ultimate effect of the thermal degradation on insulation can be evaluated with tan δ testing. Partial discharge testing may be appropriate for butyl rubber insulated cables in which softening and compression of the insulation are potential problems, although signal attenuation caused by corroded metallic shields could be a problem.

Line resonance assessment (LIRA) can be used for cables located in dry environments to determine whether an adverse localized thermal environment has affected the insulation [25]. If the effect was limited to the jacket on shielded cable, LIRA should identify no significant signal. If the insulation was affected, LIRA would give a relative indication of the severity of the effect. LIRA can be used on triplexed cable, but the jacket system would be within the boundary of the test, and the effects of aging on the insulation and jacket would not be separable. LIRA is a test method under development. Although results to date show the ability to identify thermally damaged segments, research has not been completed that indicates that LIRA can identify water-related damage or electrical trees.

Correct 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 repaired, replaced, or upgraded. If radiant energy is the source of the aging, shielding should be installed to reduce the effect to a point that is practical. 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 is known so that corrective action can be taken at the appropriate time.

Replace Thermally Damaged Cable

If severe thermal aging of the insulation is identified or suspected and cannot be eliminated by evaluation, removal and replacement of the affected cable section is recommended. If the qualified life of a cable is shortened because of the adverse localized thermal environment, it must be replaced before the end of its qualified life. Replacement of a section by using appropriate splices or replacement of the entire circuit is permissible.

High-Resistance Connections

When inspection or infrared assessment of cable connections indicates significant heating of a connection (for example, for infrared thermography: upper "intermediate" through "critical" status in Table 6-3), the affected connection should be repaired or replaced. If replacement cannot be performed immediately, increased monitoring should be performed until replacement occurs. Early replacement is recommended to preclude significant damage to the cable insulation at the connection point. If the cable insulation has been damaged, replacement of the cable or the affected section will be necessary as well.

Cables Damaged by High Current

Damage to cable from ohmic heating resulting from 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. Rectification of the cause of the high current is necessary whether it is from lack of transpositions in multi-conductor-per-phase circuits or undersized conductors.

Section 8: References

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Additional Resources

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2. IEEE Std. 400.3-2006, IEEE Guide for Partial Discharge Testing of Shielded Power Cable Systems in a Field Environment, Institute of Electrical and Electronics Engineers, Inc., New York, NY.

Appendix A: Assessment of Percent Standard Deviation of Tan δ Measurements

Section 5 describes the use of percent standard deviation as a means of evaluating tan δ results. The following is a description of the mathematical determination of the percent standard deviation and an example of its calculation, including the equation used in the determination. This equation is may be used in electronic spreadsheets such as Microsoft Excel.

$$\%STDEV = 100 * \sqrt{\frac{\sum (x - \bar{x})^2}{(n-1)}}$$

Where:

$\%STDEV$	is percent standard deviation.
X	is each individual tan δ measurement.
$\bar{x}$	is the mean (arithmetical average) of the tan δ measurements.
n	is the number of measurements.

A minimum of six measurements is recommended.

The percent standard deviation of the tan δ measurements provides a way to assess small but significant changes in tan δ at a particular voltage level. The following is an example from the C phase 8-kV (1-V_0) result from Figure 5-4. The following 14 measurements were taken over the course of 2 minutes:

8.2, 8.3, 8.3, 8.4, 8.4, 8.5, 8.5, 8.6, 8.6, 8.7, 8.7, 8.7, 8.7, and 8.8

A casual inspection might indicate no specific problem; however, under constant voltage, the tan δ measurements are increasing rather than staying stable. The mean of these results is 8.5. The rounded percent standard deviation is 0.02, placing the cable in a “further study required” state at the 1-V_0 test level.

Evaluating the percent standard deviation provided a clearer indication of a problem.

For the 1.5-V_0 test level (11.9 kV), the following 15 measurements were also taken:

15.0, 16.0, 16.8, 17.6, 18.2, 18.8, 19.3, 19.8, 20.2, 20.6, 21.0, 21.4, 21.7, 22.0, and 22.3

Scanning these data more easily indicates an ever-increasing tan δ measurement. The mean of these results is 22.3. The percent standard deviation is 0.23, which is nearly six times the "action required" level and is a strong indication of a significant degradation.

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