IEEE Std 1205-2000
(Revision of
IEEE Std 1205-1993)

IEEE Guide for Assessing, Monitoring, and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations

Sponsor

Nuclear Power Engineering Committee
of the
IEEE Power Engineering Society

Approved 30 March 2000

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Abstract: Guidelines for assessing, monitoring, and mitigating aging degradation effects on Class 1E equipment used in nuclear power generating stations are provided. This guide also includes informative annexes on aging mechanisms, environmental monitoring, condition monitoring, aging program essential attributes, and example assessments for five types of equipment (including electric cable).

Keywords: activation energy, aging, aging assessment, aging effects, aging management, aging mechanisms, Arrhenius, condition monitoring, degradation, environmental monitoring, license renewal, radiation model, residual life, stressor, thermal model

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Introduction

(This introduction is not part of IEEE Std 1205-2000, IEEE Guide for Assessing, Monitoring, and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations.)

Class 1E equipment in nuclear power generating stations must meet its safety functional requirements throughout its service life. This is accomplished through a systematic and disciplined program of quality assurance covering design, qualification, manufacturing, storage, installation, operation, maintenance, periodic testing, and surveillance. As part of the maintenance, surveillance, and periodic testing programs, Class 1E equipment is maintained in a state of readiness by various methods that include, as appropriate, periodic refurbishment and/or replacement. Also, for some Class 1E equipment located in harsh environment areas in the plant, rigorous testing and/or analysis is employed to demonstrate a qualified life. For equipment located in mild environment areas, a qualified life demonstration is generally not required; an effective program of surveillance and maintenance is sufficient to identify and mitigate potential aging degradation. Continuation of these programs should ensure that Class 1E equipment is capable of performing its intended safety function during its service life.

It is not the intent of this guide to imply that new programs be established for the purpose of aging assessment. Aging assessments should not be directed toward an endless search for data and information, but rather should be an effort that is practical, cost-effective, and based on collecting and evaluating a minimum set of data and information collected preferably from existing programs.

The service life of some equipment may include operation beyond its design or qualified life, and even beyond a plant's original license term. To accomplish this, a technical basis is necessary to demonstrate that the Class 1E equipment is capable of continued safe operation during any renewed license term of the plant. For equipment qualified to IEEE Std 323-1974 or IEEE Std 323-1983, this technical basis exists for its original qualified life. The potential for significant aging needs to be effectively assessed so that necessary mitigating actions are taken to assure dependable and safe operation of the plant, including extension beyond original qualified life.

In 1988, the Nuclear Power Engineering Committee (NPEC) of IEEE recognized a need for and directed Working Group 3.4 to prepare a guide to supplement its existing body of standards. This guide was to

— Provide guidance in the areas of aging assessment, control, and mitigation.

— Promote uniformity in the methods used for developing the technical basis cited previously.

While it would have been possible to incorporate this guide into related standards, the decision was made to develop a stand-alone document for the following reasons:

— It would be expedient and promote consistency by providing guidance that can be incorporated into future standards.

— It would help disseminate the body of knowledge and promote uniformity in application methods while minimizing the confusion that could result from the differences in the licensing bases of the various operating nuclear power plants.

The Working Group's effort culminated in 1993 with the original issue of IEEE Std 1205.

At the time of original issue of IEEE Std 1205-1993, the industry focus for assessing and mitigating aging degradation was on identifying and addressing aging mechanisms. This approach derived from the rigorous aging analyses performed in support of earlier environmental qualification (EQ) programs. In 1991, 10 CFR 50.65 (Maintenance Rule) was published. In 1995 10 CFR 54 (License Renewal Rule) was amended. As a result of these two regulation changes and industry interactions in response [e.g., NEI 95-10 (Revision 1), Industry Guideline for Implementing the Requirements of 10 CFR Part 54 — The License Renewal Rule],

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the emphasis for addressing aging degradation shifted from identifying aging mechanisms to identifying aging effects. Since the original issue of IEEE Std 1205-1993, the Working Group has also received feedback on a need to better integrate the various clauses of this guide in order to improve its usefulness.

In 1997, the NPEC authorized Working Group 3.4 to revise IEEE Std 1205-1993 to incorporate industry feedback and to bring the approaches discussed in the guide into closer conformance with present industry philosophy. To this end, the following changes to the guide have been adopted:

— Developed new block diagrams that update the aging assessment, monitoring, and mitigation process for consistency with current industry philosophy and better show and integrate the relationships between the process steps.

— Reversed the order of Clause 4 and Clause 5, and revised Clause 5, Clause 6, and Clause 7 for improved consistency with the new process block diagrams.

— Added a new Annex C on condition monitoring.

— Updated the example assessments now found in Annex D for consistency with the revised Clause 6, and added two new examples on electric cable and electric penetrations.

— Added a new Annex E on attributes of an effective aging management program.

The Working Group believes that this guide is useful in supporting EQ Program aging assessment updates, Maintenance Rule related failure evaluations, other root cause evaluations, License Renewal aging management reviews, as well as special case maintenance problem evaluations. While the scope of this guide is limited to Class 1E equipment, the principles can be applied equally well to non-Class 1E equipment.

A future activity of the Working Group is to extract candidate monitoring methods for aging effects from Table A1, evaluate continued viability, and incorporate into a future update of Annex C.

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IEEE Guide for Assessing, Monitoring, and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations

1. Overview

1.1 Scope

This document provides the guidelines for assessing, monitoring, and mitigating aging degradation effects on Class 1E equipment used in nuclear power generating stations.

1.2 Purpose

The purpose of this guide is to supplement existing IEEE nuclear standards in assessing aging degradation effects. The methods described herein can be used to identify the performance capability of Class 1E equipment beyond its qualified life.

1.3 Application

It is intended that the user determine the specific equipment that warrants attention using this guide. It is not intended that the methods described herein be required to be applied to all Class 1E equipment. For example, if aging considerations have been satisfactorily addressed through other means (e.g., equipment qualification), then use of this guide may not be warranted. Similarly, for some equipment, only partial application of this guide may be warranted.

Aging assessment may be pursued in response to a variety of factors, e.g., regulatory guidance, approaching obsolescence, reduced availability or reliability, or for life extension. For example, IEEE Std 323-1983[1] provides definitive guidance for the qualification of Class 1E equipment required to mitigate the consequences of a design basis event. Such factors plus economics also affect the method and extent of aging assessment actually performed. Monitoring and/or mitigating the aging of some equipment may be determined to be less cost effective than replacing the equipment. Running to failure may be an option under certain special situations.

[1]Information on references can be found in Clause 2.

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2. References

This guide should be used in conjunction with the following standards:

IEEE Std 323-1983 (Reaff 1996), IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations.[2]

IEEE Std 943-1986 (Reaff 1992), IEEE Guide for Aging Mechanisms and Diagnostic Procedures in Evaluating Electrical Insulation Systems.

3. Definitions

Most terms used in this guide are consistent with the recognized industry and IEEE standards. The following definitions are provided to establish the meanings of words in the context of their use in this guide. EPRI RP-2927 [B15][3] provides definitions for terms not commonly found in IEEE standards.

3.1 aging assessment: Evaluation of appropriate information for determining the effects of aging on the current and future ability of systems, structures, and components to function within acceptance criteria.

3.2 aging degradation: Gradual deterioration in the physical characteristics of a system, structure, or component, that is due to aging mechanisms, that occurs with time or use under preserves or service conditions and could impair its ability to perform any of its design functions.

3.3 aging effects: Net changes in characteristics of a system, structure, or component that occur with time or use and are due to aging mechanisms.

3.4 aging mechanism: A specific process that gradually changes the characteristics of a system, structure, or component with time or use.

3.5 residual life: The remaining period of time during which a system, structure, or component is expected to perform its safety function under specified service conditions.

3.6 service life: The actual period from initial operation to retirement of a system, structure, or component.

3.7 significant aging mechanism: An aging mechanism that, in the normal and abnormal service environment, causes degradation during the installed life of the equipment that progressively and appreciably renders the equipment vulnerable to failure to perform its safety function(s) during design basis event conditions (DBE) (see IEEE Std 649-1991 [B51]).

3.8 stressor: An agent or stimulus that stems from fabrication or preservice and service conditions and can produce immediate degradation or aging degradation of a system, structure, or component.

[2]IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA (http://standards.ieee.org/).

[3]The numbers in brackets correspond to those of the bibliography in Annex F.

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4. Stressors, aging mechanisms, and aging effects

4.1 Stressors

A stressor that stems from fabrication, preservice, or service conditions may produce aging mechanisms and effects or immediate degradation of Class 1E equipment. The following two types of stressors should be considered for aging:

a) *Environmental*. These are stressors that exist continuously in the environment surrounding the equipment, whether it is operating or shut down. Examples include vibration, heat, radiation, and humidity. Annex A provides a representative listing of stressors and their effects, while Annex B provides considerations for environmental monitoring.

b) *Operational*. These are stressors arising from equipment operation. Examples are internal heating from electrical or mechanical loading, physical stresses from mechanical or electrical surges, vibration, and abrasive wearing of parts.

The aging degradation of electrical equipment is usually be a function of the duration, range and intensity of stressors experienced by the equipment. Aging degradation due to a single stressor may usually be represented as a simple first-order relationship involving stressor intensity and time; however, aging degradation due to a combination of more than one stressor may exceed the sum of the individual effects.

4.2 Aging mechanisms and aging effects

One method of determining the susceptibility of equipment to aging mechanisms and consequent aging effects is by understanding the behavior of the individual materials that make up the Class 1E equipment, when subjected to environmental and operational stressors. These mechanisms may apply to solid-state electronic components as well as electrical equipment. Some examples of stressors, aging mechanisms, and aging effects are provided as follows:

a) High-temperature environments can cause organic insulating materials to become brittle. Moisture or physical contact may result in a loss of dielectric integrity.

b) High-humidity environments can accelerate bearing wear in rotating machinery lacking special seals or pressure lubrication.

c) High humidity can increase pitting and corrosion of contacts on relays and controllers.

d) Vibration can loosen fasteners on linkages causing misalignment of components or loss of electrical contact integrity. Misalignment accelerates wear in moving parts; loose electrical contacts may lead to heat-related degradation.

e) Support structures subject to high humidity or contact with water and / or chemicals may corrode if not protected by coatings or covers.

f) Radiation can break down the antioxidation chemicals in organic insulation materials and produce embrittlement similar to that caused by high temperature.

g) Continuous operation of certain electronic components (e.g., diodes, resistors) at high ambient temperatures can cause operation outside of their performance specification or circuit drift.

h) Excessive voltage cycling can result in premature failure of electrolytic capacitors.

i) Exposure to moisture can result in delamination of insulated wires.

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Table A.1, Table A.2, and Table A.3 provide, in summary form, a listing of typical aging mechanisms and their effects on polymers, lubricants, and metals.

All mechanisms may not be operative or produce significant aging effects in equipment in a given service environment for a given period of time. In some cases, aging mechanisms may be readily judged to be of little or no importance because they are not significant relative to the equipment safety function. For example, metals in electronic components (except at electrical contact points or other areas susceptible to corrosion) may not require aging assessment.

The information in Table A.1, Table A.2, and Table A.3 may be supplemented by other information on aging effects such as operating experience, manufacturer's data, expert opinion, research and test data, and demonstrated performance capability from environmental qualifications.

5. Discussion

5.1 Need for an aging assessment

The first step in performing an aging assessment is to establish the population to be addressed. The description of the aging assessment process in this guide assumes that a judgment has already been made that an aging assessment is needed. However, potential reasons for performing an aging assessment may include

— Industry-identified equipment problem evaluation
— Plant-specific equipment problem evaluation
— License renewal equipment review
— Maintenance rule equipment failure evaluation
— Equipment qualification aging-related problems

An aging assessment evaluation may not be necessary if the equipment is affected by

— Obsolescence (e.g., superseded technology, lack of vendor support)
— A lack of a viable source of spare parts
— IEEE Std 323-1983 requalification (e.g., a retest decision has been made)
— Replacement or attention for other reasons (e.g., regulatory requirements)

Figure 1 provides an overview of the aging assessment process by illustrating the main activities.

5.2 Desired objective and benefits

The purpose of performing an aging assessment is to establish the technical basis that demonstrates the continued safety and functional performance capability of Class 1E equipment. Such an aging assessment may require some understanding of the type of stressors, the nature of the aging mechanisms affecting the equipment, and the often more discernible resultant aging effects (refer to Annex A).

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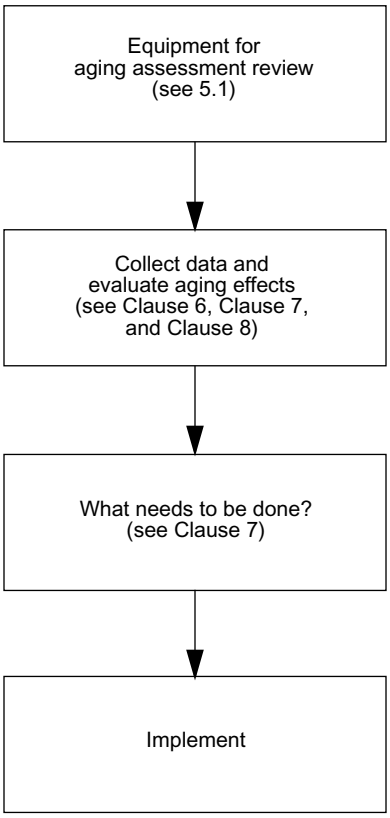


Figure 1—Overview of assessing, monitoring, and mitigating aging effects

Beyond the purpose stated previously, an aging assessment at a nuclear power plant is often performed in a larger context of a desire for improved safety and operation of the overall plant. Understanding the aging mechanisms that affect Class 1E equipment in a nuclear power generating station permits the identification, monitoring, and mitigation of aging effects (aging degradation) that can significantly effect the performance of a safety function. An aging assessment may provide the station with improved safety through fewer challenges to the safety systems and avoidance of forced outages.

The knowledge gained by understanding the significant aging mechanisms and effects, and the potential for failures they can cause, could be integrated into the operational surveillance programs and preventive maintenance programs at nuclear power generating stations. With a knowledge of significant aging effects, surveillance activities may be tailored to collect the necessary data to assess aging, and maintenance programs may be designed to identify the need for repair or replacement of age-degraded Class 1E equipment or components. For example, activities such as transformer oil analysis, equipment hot-spot mapping using infrared thermography, vibration monitoring of motors, and root cause analysis of equipment failures are existing plant activities that can be directed toward aging assessment. A combination of some of these programs should be all that is needed to assess aging degradation for some equipment. For example, for valve motor actuators, existing programs of preventive maintenance and root cause analysis of failures coupled with trending data from condition monitoring techniques or current signature analysis should yield sufficient data to perform an aging assessment.

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5.3 Aging assessment elements

Aging assessments are performed at nuclear power plants on a routine basis, although they may not be identified as such. A brief discussion of typical elements of an aging assessment process follows.

Clause 4 establishes the relationship between aging mechanisms and aging effects. The identification of known operational stressors, aging mechanisms, and the resultant aging effects can be useful elements in an aging assessment process. It should be understood that there is no intended order of performance with regard to investigating aging mechanisms and aging effects. Specific knowledge of the equipment and its service conditions (stressors) should be applied to determine if any significant aging effects are discernible or if aging mechanisms may be considered to provide insight to aging effects not yet apparent.

Once the equipment is selected for evaluation, several pieces of information are collected to form the technical basis for an aging effect assessment. The actions that should be performed are

a) Define and determine the equipment boundaries relative to what is going to be included in the aging assessment process
b) Identify the equipment's safety functions
c) Identify the equipment's installed location
d) Identify the stressors operating on the equipment
e) Identify the parts and materials included in the equipment's assembly
f) Identify and assess the aging effects on the equipment

An assessment of the aging effects on the equipment is done to determine if a reasonable correlation can be made with respect to the stressors that exist in the equipment's installed location, a material's sensitivity to the stressors, and a loss of equipment function. If a correlation is apparent, an aging mechanism may be identified. As a minimum, the assessment should be comprehensive enough to support and implement an effective aging management decision. Following implementation, the actions should be validated or refined as needed. Figure 2 defines the individual elements of the aging assessment process. The process shown in Figure 2 combined with the insight from Clause 4, Annex A, Annex C, and the existing environmental qualification (EQ) equipment documentation are integrated to obtain a sufficient technical basis to determine an aging mitigation solution.

NOTE—The process of implementing aging management would most likely be an iterative one. That is, the results of monitoring and mitigating aging effects would allow future refinement of the aging assessment.

6. Aging assessment

Clause 6 provides guidance for data collection (see Clause 8) in support of the aging assessment and also for performing the aging assessment. The level of detail selected for aging assessments should be determined prior to starting the evaluation. The level of detail selected in most cases need only provide reasonable assurance of equipment safety function.

6.1 Define evaluation boundaries

The boundaries of the evaluation should be defined for the purposes of the aging effect assessment and clearly define the parts or portion of the equipment to be examined. The need for a clear definition is especially true where equipment to be evaluated interfaces with field cables or other equipment. The boundary should determine inclusion or exclusion of equipment, parts, or connections external to the device being evaluated. A description of the equipment and its boundaries being evaluated, not discussed elsewhere in the evaluation, should be provided.

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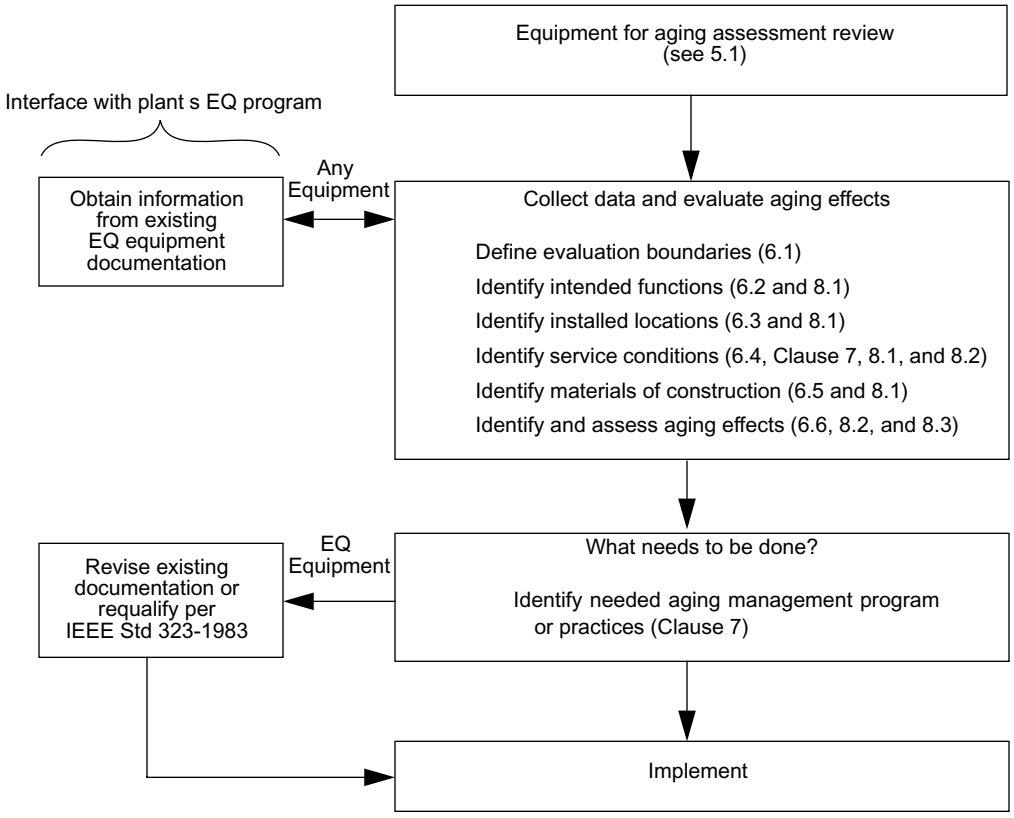


Figure 2—Process for assessing, monitoring, and mitigating aging effects

6.2 Identify equipment safety functions

Equipment safety functions are those that are essential to the system's safety function. For more complex pieces of equipment (e.g., emergency diesel generators), it would also be important to identify subassembly safety functions. For purposes of performing an aging assessment, the following functions should be identified:

a) Equipment safety functions susceptible to known aging effects

b) Subassembly safety functions susceptible to known aging effects

c) Equipment and subassembly support functions whose degradation or failure could cause loss of a safety function (e.g., electrical penetration O-ring performing a pressure-retention function)

Typical sources of information pertaining to equipment safety functions are provided in 8.1.

6.3 Identify plant locations where the equipment is installed

It is important to identify the location where the equipment is installed in the plant. Location information is needed for determining service conditions. Typical sources of equipment locations are plant drawings, equipment databases, and plant walkdowns.

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6.4 Identify the electrical equipment service conditions

The electrical equipment's service conditions are determined in order to assess the influences that can affect its service life. Service conditions include both environmental conditions (e.g., thermal, radiation, moisture) and, if applicable, equipment operational conditions (e.g., self-heating, vibration). These service conditions are the stressors that may cause aging of the electrical equipment. Annex A identifies other stressors that may be applicable to equipment.

Environmental temperatures for most plant areas are normally available in various heating, ventilation, and air conditioning (HVAC) design specifications, station safety analysis reports, or design basis documents. For areas in which equipment temperature data is not available or the existing data requires reevaluation, new temperature data should be gathered. In addition to the ambient thermal environment, temperature rise due to component self-heating can also contribute to equipment thermal aging and, where applicable, should be addressed in the evaluation. Equipment self-heating temperature rise information can be obtained from manufacturers' data, from equipment item specific analyses, or from tests. Self-heating temperature rise is added to the ambient temperature to determine the total temperature to be considered for thermal aging of the equipment and materials.

Radiation data, for plant areas where it is applicable, is normally available from the station safety analysis report or from the plant EQ program as radiation mapping is normally done to determine normal electrical equipment radiation doses in applicable plant areas. In those instances where no radiation data is available, it may be obtained from the plant surveys.

Humidity for plant areas, if needed, can be obtained from HVAC design specifications, station safety analysis report, or periodic plant monitoring, or can be conservatively established.

Cyclic stresses are an operative concern depending on the degree of the stress and the number of cycles. A cyclic stress service condition need only be identified for the aging assessment if there are known aging effects. Examples are mechanical and electrical cycling. See Annex A for additional information.

Sources of design and actual service condition data can be found in 8.1 and 8.2. Information on monitoring of environments is contained in Annex B. In addition, EPRI TR-109619 [B10] provides guidance for obtaining service condition data.

6.5 Identify the materials of construction

The equipment's parts and construction materials should be identified for evaluation under their service conditions. In cases where it is not possible to determine all materials or the exact materials of construction, the goal is to have reasonable assurance that age-sensitive materials have been identified.

Electrical component materials can be identified from various sources such as from design material lists, component manufacturer drawings, or spectrographic analysis. See 8.1 for additional sources of information. Where specific component information is lacking, industry aging management guidelines and other reports (e.g., NUREG-1377 [B65], NUREG/CR 3629 [B66], NUREG/CR 4156 [B67], NUREG/CR-4731 [B68], NUREG/CR-4715 [B69], NUREG/CR 4740 [B70], NUREG/CR-5051 [B71], NUREG/CR-5057 [B72], SAND96-0344 [B74]) may be sources of the most common materials used for specific component types installed in the nuclear power industry.

Electrical components are constructed with organic and inorganic materials. Depending on the type of component being evaluated, identification of the metals and other inorganic materials may not be necessary. For example, there are no significant aging effects for inorganic materials associated with cables (i.e., cable conductor, shielding, fillers and armor).

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NOTE—Most metals and other inorganic parts in cables are covered by insulation or a jacket and are not exposed to environments that would cause the inorganic materials to degrade under normal circumstances. Although not typical, moisture can seep between various layers of cable construction and with oxygen introduced can cause corrosion and metal loss. Contacts, linkages, and bearings are inorganic parts of electrical equipment that may also be susceptible to aging.

6.6 Identify and assess aging effects

Aging effects are identified and assessed to determine whether any additional aging management efforts are needed to prevent the effects from becoming significant over time. Significant aging effects are those that can detrimentally affect the equipment safety function or functions identified in 6.2.

The following subclauses describe aging effect identification, other supportive information needed, and use of aging models and condition monitoring to perform aging assessments.

6.6.1 Identification of aging effects

Aging effects are identified from either plant-specific or industry failure or degradation experience with the specific equipment or its materials of construction (from 6.5) in a similar application. Alternatively, plant-specific service conditions (stressor values) and materials information may be used to determine applicable and potentially significant aging effects from the tables of Annex A.

6.6.2 Other supportive information needed

Next the following information should be researched or established as feasible or available:

a) Evaluation period: Most materials degrade somewhat over time, even in fairly benign environments; it is useful to set a specific goal for the equipment's life to be evaluated. The evaluation period is normally selected on the basis of the plant's 40-year operating license, but can be selected for any other specific time period (e.g., outage to outage for specific equipment, time periods between tests as dictated by safety analysis, or 60 years for license renewal).

   NOTE—For EQ Program equipment, it is necessary to include the mission (or postaccident required operating) time in the evaluation period to assure sufficient margin for postaccident operability beyond the normal life goal.

b) Past and future service conditions (from 6.4) as a function of time or as enveloping values for the evaluation period.

c) Degree of flexibility in controlling or limiting future service conditions.

d) Aging mechanisms likely to cause the identified aging effects in the identified materials of construction (determined from Annex A or similar sources of information, such as EPRI NP-1558 [B12] and NUREG-1377 [B65], NUREG/CR-3629 [B66], NUREG/CR-4156 [B67], NUREG/CR-4731 [B68], NUREG/CR-4715 [B69], NUREG/CR-4740 [B70], NUREG/CR-5051 [B71], NUREG/CR-5057 [B72]).

e) Dependence of the aging mechanism and resulting aging effects on the identified service conditions.

f) Aging information, such as activation energy, accelerated aging test data (temperature and time), temperature rating or maximum continuous-use temperature, radiation dose threshold, and related information, for the equipment or its materials of construction.

To perform the aging assessment, the material's withstand capability is compared to the intensity of a service condition stressor. Results from tests of material properties, after being subjected to accelerated aging, are the best and most readily available sources of material aging information. Other sources include utility

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experience and industry aging management guides such as those published by the Department of Energy and the Electric Power Research Institute (EPRI), e.g., EPRI EL-5885 [B11], EPRI NP-1558 [B12], NUREG-1377 [B65], NUREG/CR-3629 [B66], NUREG/CR-4156 [B67], NUREG/CR-4731 [B68], NUREG/CR-4715 [B69], NUREG/CR-4740 [B70], NUREG/CR-5051 [B71], NUREG/CR-5057 [B72], SAND96-0344 [B74], and NUREG/CR-6384 [B73].

The aging assessment can be performed to achieve either one or both of the following objectives, depending on information availability, expected or estimated remaining life margin, and whether specific equipment life goals have been established or are needed. The objectives of the aging assessment are to determine

— How long (years) a material will remain functional while exposed to its stressors, or

— A maximum stressor (heat, radiation) value that a material would be able to withstand for a specified period (years) and still remain functional.

Knowing the equipment materials and stressors, it is possible to assess the effects of aging on the material to date and to determine how in the future aging will affect the equipment safety function. For a given material, aging effects (some type of material degradation) can be directly related to a specific environmental or operational stressor. The intensity of the stressor normally determines the rate that the material degrades.

Next, one or a combination of methods is used to assess aging effects for the equipment's future service conditions. Two models, which extrapolate test results and condition monitoring, are discussed in the following subclause.

6.6.3 Use of a thermal aging model

Thermal aging is commonly assessed by using the Arrhenius model, which is described in EPRI NP-1558 [B12] and Nelson [B58]. The model establishes aging degradation as a function of temperature and allows an estimation of thermal life at a given temperature. It is also used to relate remaining life at one temperature to remaining life at another temperature. Alternatively, it can be used to determine a maximum continuous temperature for a specific length of time.

Thermal aging is a chemical reaction, and such reactions are a function of temperature. The reaction rate (dg/dt) according to Arrhenius from EPRI NP-1558 [B12] and Nelson [B58] is given in Equation (1).

$$\frac{dg}{dt} = A \exp(-\phi/\mathrm{k}T) \tag{1}$$

Neglecting the effect of depletion of the reactants on the reaction rate to solve this differential equation gives Equation (2).

$$t = B \exp(\phi/\mathrm{k}T) \tag{2}$$

where

t is the time to reach a specified end-of-qualified-life condition or lifetime,

A is a constant of proportionality,

B is a constant [related to the amount of degradation that will have occurred at end of time t or $B = g(t)/A$ where $g(t)$ is the amount of reactions occurring through time t],

ϕ is the activation energy (eV) for a chemical reaction of concern and indicative of aging susceptibility,

k is the Boltzmann's constant (0.817×10^{-4} eV/K),

T is the absolute temperature (K) of the service condition.

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Equivalent degradation can be applied to the Arrhenius relationship to allow calculation of a lifetime t_2 at an actual (or expected) installed temperature T_2, given a different test temperature T_1 and a test period t_1 [see Equation (3)].

$$t_2/t_1 = \exp\{(\phi/k)[(1/T_2) - (1/T_1)]\} \quad (3)$$

Equation (3) can be used in conjunction with appropriate testing results (to a marginal degradation condition) at a higher temperature to theoretically derive a maximum continuous-use lower temperature for a longer specified period of time. Alternatively, this expression can be used to approximate remaining life given a known exposure temperature history and a conservative expected future temperature. To facilitate such a determination, a series of i discrete "time at temperature" intervals can be used to derive an equivalent Arrhenius weighted average temperature T_n for the entire period of time t_n as shown in Equation (4).

$$g(t_n) = At_n[\exp(-\phi/kT_n)] = A[t_1 \exp(-\phi/kT_1) + t_2 \exp(-\phi/kT_2) + \ldots + t_i \exp(-\phi/kT_i)] \quad (4)$$

$$T_n = (\phi/k)/\ln[t_n/\sum t_i \exp(-\phi/kT_1)]$$

where T_i is the temperature for time interval t_i and the summation is over all i discrete intervals.

It should be noted that Arrhenius thermal age modeling has the following assumptions, sensitivities, and limitations:

a) A single stressor type, i.e., thermal aging is assumed at work throughout the life of the material. (Radiation exposure degradation and other forms of aging would need to be addressed separately.)

b) One dominating chemical reaction corresponding to one dominating aging mechanism causing the identified aging effect (e.g., corrosion, embrittlement, etc.) is assumed. (Test temperatures should be selected to assure that the dominant aging reaction at the test conditions is also dominant and equivalent at the installed service condition temperature.)

c) The coefficient A is assumed to be independent of temperature. According to gaseous reaction theory, A increases at approximately the square root of temperature.

   NOTE—It is square root dependent when both reactants are gases; for solid material aging, only one of the reactants (oxygen) is normally gaseous and A would be less temperature dependent. This assumption could cause the reaction rate or amount of reactions to be calculated lower than actual, but the error is small—less than 5% for typical ambient and test temperatures—and this error would be offset by other conservative assumptions.

d) The activation energy is considered to be constant with temperature and time. (The selected activation energy should be at the conservative end of the range of possible activation energies.)

e) Equation (1), Equation (2), Equation (3), and Equation (4) are very sensitive to the accuracy of the selected activation energy. Because the activation energy is often available in only one or two significant digits, it should be selected carefully and the expression results interpreted judiciously. (That is, calculated results with accuracy beyond one or two significant digits are not considered credible.)

f) The reaction rate is assumed to be not affected by depletion of the reactant concentration; in other words, the end of life (amount of degradation) is selected to be before depletion effects are noticeable.

   NOTE—This assumption is conservative because reactant depletion reduces the aging reaction rate, which would give a longer predicted life given a life endpoint based on the same amount of degradation.

g) Equation (3) assumes the same amount of degradation damage when converting from one set of time at temperature conditions to another set of conditions. (This amount of damage does not necessarily represent an end-of-life condition.)

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Because of the limitations and assumptions stated previously, the Arrhenius model for thermal aging should be considered to provide only an approximation of the lifetime of the equipment. When feasible, condition monitoring or other means should be considered to validate remaining or residual life of equipment.

6.6.4 Use of a radiation aging model

Unlike thermal exposure, the radiation dosage or amount of energy deposited affecting a material's integrity and operability linearly increases with time for a constant field or dose rate. A conventional model for radiation aging assumes that material damage is directly related to the amount of energy deposited as a result of exposure in an ionizing radiation field. This model also assumes a principle of equivalent damage exists. This principle states that the amount of material damage resulting from exposure to a constant radiation dose rate field and a given duration is equivalent to that same exposure from any other combination of dose rates and exposure durations. The total integrated dose is the time integral of the dose rate as a function of time over the total exposure duration.

The value of total integrated dose that begins to detrimentally affect the material's functionality and, thereby, the equipment's ability to perform its safety function can be determined by test and has been tabulated for many materials. Therefore, an assessment of the effects of radiation aging would be a determination of remaining life to achievement of a detrimental-to-function dose at the expected service condition dose rate.

6.6.5 Condition monitoring

Condition monitoring can be used to determine and predict the physical and operating status of equipment. The condition of a limiting weak link part is normally used as an indicator to determine the overall condition of the equipment. The condition of the weak link material or part is ascertained by comparing some age-dependent or trendable material property or other observable parameter to a baseline value (usually the value when new) or an end condition (determined from the acceptance criteria).

Appropriate condition monitoring techniques should be identified and data should be collected at various stages in the life of the equipment to establish a performance history. This history can then be used to identify trends, which would provide insights for determining current equipment condition, as well as predicting equipment future performance and residual life.

Annex C contains additional information on condition monitoring techniques, which may be used to perform or support the aging assessment. In addition, many IEEE standards provide guidance for evaluating, testing, and maintaining electrical insulation systems [see the relevant examples of IEEE standards in Annex F ([B16], [B20], [B21], [B22], [B23], [B53], [B54], [B55] [B56], [B50], [B17], [B18], [B19], [B25], [B26], [B27], [B30], [B40], [B41], [B42], [B43], [B45], [B48], and [B57])].

6.6.6 Summary

An aging assessment approach can be summarized as follows:

a) Identify aging effects that may become significant based on site-specific or industry-available degradation data.

b) Determine the specific duration and end-of-qualified-life condition of the aging effect assessment. Collect aging information for materials identified as being part of the electrical equipment as it relates to applicable environmental stressors.

c) Use an aging model to determine maximum stressor values (normal and accident conditions) that each material would be able to withstand for the evaluation period and still remain functional.

d) Compare the actual service condition stressor values with each material maximum stressor value. The actual service condition stressor values are expected to be less than the maximum stressor value

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for each material or a result of the margin provided by the original design basis. If an actual service condition stressor value is greater than a material maximum stressor value, aging management may be required to preserve the material or equipment safety function. If so, determine how long a material would remain functional while being exposed to its actual service conditions.

e) Obtain and review condition monitoring data to perform or validate the aging analyses.

7. Monitoring and mitigating aging degradation

Clause 6 defines the process for performing an aging assessment and for collecting data in support of this process. The assessment determines those aging effects that require further or continuing monitoring and mitigative action. These actions consist of maintaining, improving, or replacing the equipment (7.1 through 7.4); reducing environmental or operating stressors (7.5); or collecting more data (7.6 through 7.9) in support of future actions to maintain, improve, or replace the equipment. Annex C contains additional guidance on condition monitoring techniques, which could be used in support of mitigative actions.

7.1 Maintenance

Maintenance consists of the actions that detect, preclude, or mitigate degradation of equipment. Maintenance is most effective when performed on a timely basis. The following is an approach to determine when to perform maintenance:

a) Identify methods to detect aging degradation prior to failure.

b) Perform condition/failure trending (see 7.9), as appropriate, for equipment under observation.

c) Determine minimum functional capability that defines the end of normal service life while being capable of performing its safety function.

d) Analyze the data collected from the previous process and decide the appropriate corrective action.

Detection and mitigation of significant aging degradation effects is accomplished through preventive maintenance, which includes those maintenance activities performed on a periodic, continuous, or predictive basis prior to failure.

Requirements to maintain the EQ of Class 1E equipment are integrated into maintenance / operational programs. Utilities have established an Environmental Qualification program for Class 1E equipment located in potentially harsh post-accident environments. Two techniques that are currently used for mitigating aging degradation in an EQ program are (a) reconfiguration or operational changes to reduce aging environmental stressor (principally heat and radiation) levels and (b) replacement.

7.2 Replacement

Replacement is the substitution of a component, usually degraded or failed, with another that complies with the design requirements. Components may be replaced prior to reaching the end of design or qualified life or prior to failure based on the results of monitoring or operating history of similar equipment. For instance, in equipment qualification programs, weak link components are replaced prior to the end of their qualified life so that the longer qualified life of the host equipment is maintained.

Replacement is also an option to use for equipment that has become obsolete (obsolescence alone is not cause for replacement), equipment for which spare parts are no longer available, equipment that fails to meet acceptance criteria, or equipment for which increased reliability is desired.

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7.3 Refurbishment

Refurbishment is the renovation or restoration of a degraded component to an acceptable state, not necessarily its original, nondegraded state. The equipment to be refurbished may have selected components or materials replaced. Examples of refurbishment of equipment are changing the contacts on a breaker, installing new bearings on a motor, or replacing insulation materials. It should be noted that environmental qualification requirements, when applicable, should be satisfied for refurbished equipment.

7.4 Redesign of equipment

Equipment manufacturers and the nuclear industry routinely perform design enhancements based on operating experience and new technology / materials availability. These include changing to materials more resistant to aging stressors, reconfiguring for improved reliability, and even relocating equipment. For example, research NUREG/CR-5051 [B71] conducted on inverters recommended age-mitigating design improvements such as the use of higher ratings for voltage- and temperature-sensitive components in the inverter circuitry and the addition of forced-air cooling to reduce overheating problems. It should be noted that the environmental qualification requirements, when applicable, should still be satisfied for redesigned equipment.

7.5 Adjustments in operating environments and practices that reduce stresses

Environmental stressors such as heat and radiation are known to induce aging degradation, particularly in organic materials. Adjustment in the operating environment or operational practices is an effective method of mitigating aging degradation. Collection and evaluation of environmental data can provide the basis for making adjustments in the environmental or operating practices that can mitigate the aging degradation effects from these stressors. Examples of adjustments in the operating environment include adding thermal insulation, venting electrical enclosures, implementing HVAC upgrades, adding radiation shielding, minimizing location of aging-sensitive equipment in a nonbenign environment and periodically decontaminating piping near Class 1E equipment. Annex B contains guidance on environmental monitoring of components. Examples of adjustments in operating practices include reducing the period of operation, reducing the number and rate of start-ups / shutdowns and optimizing or improving testing practices. In addition, EPRI TR-109619 [B10] provides guidance for management of adverse operating environments.

7.6 Environmental and operational stress monitoring

Monitoring can be used to obtain additional data for a future aging assessment or to modify actions from a prior assessment. Monitoring includes, but is not limited to, the following:

a) Environmental monitoring (e.g., temperature, radiation)

b) Power system monitoring (e.g., system voltage, current, load, response time, setpoint drift, contact resistance change)

c) Process monitoring (e.g., operating cycle / frequency)

7.7 Inspection

Certain types of degradation can be detected prior to equipment failure through routine inspections. These inspections can be designed to identify indications of equipment condition and potential abnormalities. Such indications include, but are not limited to the following:

a) Ambient environment variations

b) Bent parts

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c) Color change

d) Corrosion

e) Cracks

f) Dirt, dust, and contamination

g) Embrittlement

h) Erosion

i) Excessive heat

j) Excessive lubrication

k) Excessive vibration

l) Mechanical wear

m) Noise

n) Water in grease and lube oil

In addition, EPRI TR-109619 [B10] provides guidance for performing walkdowns and inspections. Table A.1, Table A.2, and Table A.3 list typical aging degradation effects from the previous indications.

7.8 Surveillance

Aging degradation may be detected prior to equipment failure through existing plant surveillance or diagnostic testing programs. Such programs include, but are not limited to, the following:

a) Technical specification surveillance tests

b) In-service inspection tests

c) Calibration of instrument sensors

d) Vibration analysis tests

e) Other signature analysis (e.g., motor current)

Plant setpoint monitoring programs also provide a method of monitoring the aging degradation of equipment. In this program, instrument drift is utilized as an indication of overall health of the equipment.

IEEE Std 943-1986 provides a listing of suggested tests for the detection of aging degradation in electrical insulating systems. These tests are categorized according to the effect on the equipment.

7.9 Trending

Trending of monitoring, inspection, or surveillance results (condition trending) provides an indication of aging degradation and the current and future ability of equipment to function as designed. For example, trending of results from monitoring drift in meter and instrument setpoint readings provide information that can be used to determine calibration intervals. Should the trending indicate aging is significant, instruments and meters can be removed and repaired or replaced. Trending special or periodic test results or inspections is another technique for monitoring of equipment condition and associated aging degradation. For example, for batteries, trending of performance test results, specific gravity measurements, electrolyte level, or plate inspection data should yield sufficient information to assess aging degradation. Examples of trending special or periodic test results follow. For battery chargers, these could include measuring power factor, no-load current, the limits on the current limiter, or the increase in ripple in the dc output for sudden increases and

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decreases applied to the line voltage (which could be attributed to aging degradation of the dc electrolytic filter capacitor). For oil-filled transformers, these could include gas analysis, interfacial tension, hot-spot temperature, or color test. For containment electrical penetrations, these could include leak rate tests. For temperature sensors, these could include repeatability, time constant, response time, and drift.

Condition trending does not always provide a reliable indication of aging degradation. Electronic equipment, for example, can fail catastrophically rather than provide easily detectable indications of degradation. For this type of equipment, trending failure rates may be an appropriate method of monitoring aging degradation. If statistical data are available, then surveillance, preventive maintenance, or replacement can be scheduled more effectively on the basis of failure trends. If the failure pattern of a component shows that the probability of failure increases significantly after a certain life span, then planned periodic replacement of the equipment may be considered.

Failure trending requires a systematic collection and analysis of plant data (see Clause 8 and 10 CFR 50.49 [B7]). Equipment failures should be recorded in a specified, systematic manner to permit determination of the severity of failures, failure modes, and root causes of failures. Trends of failures and their causes may then be monitored and evaluated. Some examples of trending applications are provided in Annex C.

8. Data

The compilation of relevant information on the Class 1E equipment under evaluation is a cornerstone activity of aging assessments. Relevant data should form the basis on which decisions concerning the suitability of electrical equipment for continued operation can be made.

Since many kinds and types of records and data can be considered for review, a means to identify relevant data is helpful with respect to the goals of this guide. Relevant data can be identified or suggested by first identifying the aging effects (Clause 4) that are operative for the equipment or component under scrutiny. The relevant data should support the observable parameters (Clause 6) determined for that equipment. If the aging assessment determines that additional data is required, then additional data should be identified by a more focused selection of observable parameters. Specific data generated as a result of an aging assessment (Clause 5 and Clause 6) should obviously be included as a part of this data set. Records or relevant data should be retained in accordance with plant requirements. EPRI TR-109619 [B10] provides additional guidance for data research.

The process of identifying relevant data and aging effects would most likely be an iterative one. That is, an initial level of awareness concerning the operative significant aging effects would steer the collection of the relevant data. As the data is reviewed, awareness or understanding of the aging effects may become more specific and refined. The increased understanding may warrant additional data collection. Thus, the cycle can continue until the significant aging effects are identified.

Data may be organized into three major groups:

a) Baseline data (original capability)

b) Historical data (operating history)

c) Inspections and diagnostic testing data

Essentially, the data groups emphasize a logical progression of fact finding and attempt to answer the following basic questions:

— What was the equipment's original design basis?

— How well did it perform in service?

— What is its present condition with respect to its safety function?

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8.1 Baseline data (original capability)

The evaluation of any set of relevant historical data begins with a comparison to a reference or baseline data. The baseline data describe, in detail, the original design features and capability that the Class 1E equipment had at the time of initial operation. Baseline data can be found in the following sources:

a) *Equipment specifications*. Contain the characteristics of the equipment (e.g., capacity, voltage, horsepower).

b) *Purchase orders*. List and describe the specific deliverables concerning the equipment order. Deliverables of hardware and important literature / software (e.g., certificate of conformance) should be noted as well as any special terms or conditions or options concerning the equipment.

c) *Manufacturer's information*. Can range from catalog data, application recommendations, and bulletins to very detailed reports and comprehensive test results.

d) *Equipment qualification reports*. Contain data required by various IEEE standards, which clearly show that the equipment's performance satisfies or exceeds the standards and criteria noted in the equipment's specification and purchase order. This type of data emphasizes environmental concerns related to equipment performance during a design basis accident.

e) *System preoperational or acceptance tests*. Performed after equipment installation, these tests verify that the equipment performs satisfactorily, as an individual component and within its respective system. These test records contain actual performance parameters (e.g., power consumption, temperature rise, rated output, and time response), which can then be compared to more current performance data.

f) *Equipment technical manuals*. Can contain information and explanations of the equipment's performance and maintenance requirements.

g) *Equipment nameplate*. In many cases, the information noted on the nameplate may simply confirm specification and purchase order information. In other cases, the nameplate may be one of the few available sources where information can be obtained.

h) *Final safety analysis reports (FSARs and updated FSARs)*. Contain specific design information for systems including seismic and environmental data. The plant FSAR should be a very convenient and useful source to establish a comprehensive overview prior to investigating specific details.

The preceding data sources should, in general, be available for use at any nuclear power generating station. However, this list is not intended to be all-inclusive, and other data sources may be available. It should also be noted that some data sources are more appropriate for certain kinds of data than others. This observation is made because the data suggesting the operative aging effects specific to the equipment would not be addressed in every data source. For example, while the FSAR describes the equipment's environmental design requirements, the most likely source for complete details is the equipment qualification reports prepared by the equipment manufacturer and / or the utility or industry groups. The other sources may be of assistance, but to a lesser degree. A good working knowledge of the available data sources and insights to the most likely aging effects can serve to expedite the required research.

8.2 Historical data (operating history)

A review of the equipment's performance in actual service under various types of service conditions establishes the next relevant data necessary to support the aging assessment goal. The major sources of this data set can be found, by and large, in the records kept by the plant.

a) *Equipment operating records*. Contain records that may specify / quantify when equipment is energized / de-energized (number or cycles or indications of duty cycle) or an abnormal equipment response (failure). Data from operating logs can reveal actual equipment responses to real plant

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conditions. Such information can help identify various stressors (Clause 5 and Annex A) such as overload conditions or frequent cycling of a breaker.

b) *Service condition records*. These records can reveal the specific stressors that may be significant to the aging assessment of the equipment, such as temperature, radiation, humidity, or cleanliness. (See Annex B for environmental monitoring considerations.)

c) *Event records*. These records may be used to review when a particular sequence of events is significant such as an automatic equipment actuation to a defined event (e.g., turbine or reactor trip). Event records can also show response times and highlight out-of-tolerance indications.

d) *Maintenance records*. These records may indicate routine and corrective maintenance that the equipment has received and the frequency of the maintenance performed. “As-found” and “as-left” conditions may also be noted within the records, which may provide additional insight to the operative aging effects. Maintenance records can be a very significant resource for supporting a trend analysis because they may contain information that is attainable only when the equipment is de-energized. The off-line condition provides for more detailed observations that are not feasible with the equipment online (e.g., insulation resistance, detailed visual inspections of equipment interior areas, linearity and accuracy verifications).

e) *Surveillance testing records*. These records often contain the results of observations and / or measurements of the equipment’s physical condition or performance. The data confirms that the equipment conforms to the identified acceptance criteria. These records can be used to trend equipment performance and permit measured data to be routinely compared.

f) *Outage inspections*. The extended off-line equipment status presented by the normal plant outage schedule provides the opportunity to examine Class 1E equipment in even greater detail. For example, normal surveillance testing can verify that the processing circuitry of an instrument is performing within limits. However, the outage condition allows for the additional testing of the transmitter and cabling, provided that the equipment can be de-energized.

g) *Equipment failure records*. Equipment operational failure can be an obvious indication of aging effects. The analysis of failure data can

   1) Validate the application of the equipment and its maintenance requirements
   2) Reveal inadequacies of the equipment design or maintenance
   3) Reveal conditions that subjected the equipment to stressors not accounted for in the original design
   4) Predict failures through trending

Failure data collected at any plant can be supplemented by data existent in databases such as the Nuclear Plant Reliability Data System, NRC bulletins and notices, and the Government Industry Data Exchange Program. Analysis of equipment failures can be made by a review of information from these databases, since their sample size is more extensive.

Equipment failure records may also contain data that describes the results of detailed investigations on the failed components. Such investigations may concern material analysis, and destructive and nondestructive physical testing. Table 1 of IEEE Std 943-1986 shows how a component can be examined before and after failure (e.g., insulation resistance, hardness, chemical properties).

8.3 Diagnostic testing data

Diagnostic testing is performed to establish the operating status or condition of the equipment. The purpose of diagnostic testing is threefold. First, diagnostic testing establishes the present operating condition of the equipment. Second, it provides supplemental information with respect to the historical operation data. Third, it provides information useful to assess future performance.

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In its simplest form, diagnostic testing may involve routine calibration procedures, such as that of an instrument channel. A more complex test may require evaluation of subassemblies such as individual circuit boards. The extent of the testing is heavily influenced by the materials and construction of the equipment and the identified stressors that act on it over time (see Annex A). It is noted for emphasis that testing may become iterative as the operative stressors become better defined.

Included in this effort is testing or inspections of the equipment that may be included in any of the historical data. Additional testing and inspection can be performed when historical data is insufficient to support an aging assessment.

Diagnostic testing may also be useful in establishing that the actual operating mode of the equipment is less stressful than anticipated in design (e.g., operating temperatures are lower than originally specified), which tends to suggest a longer service life as the stressor may not be as significant as originally expected.

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Annex A

(informative)

Aging effect tables

A.1 Introduction

Table A.1, Table A.2, and Table A.3 presented in this annex are included for reference information. They may be used in the basic approach for determining aging effects in Class 1E equipment. The tables refer to three classes of materials-polymers, lubricants and metals. Each table contains the following types of information:

a) Aging stressors

b) Aging mechanisms

c) Aging effects

d) Monitoring methods for aging effect

The tables in this section are intended to assist in performing aging assessments for equipment within the scope of this guide. The stressors, aging mechanisms, and aging effects listed may not be significant for all component types and the monitoring methods listed are simply typical examples of known methods. There is no implication that all of the methods are effective under all circumstances for all components. It needs to be recognized that some of the methods are still under development. Furthermore, it is intended that users of these tables consider cost-effectiveness in the selection of monitoring methods for aging management.

A.2 Use of the equipment aging tables

The following is a systematic process for using the equipment aging tables:

a) Establish the equipment boundary of interest; determine interfaces at the boundary as defined in 6.1.

b) Collect relevant data for the specific equipment of interest as described in Clause 8.

c) Identify materials known to have propensity for aging and to be susceptible to degradation in the equipment service conditions. Materials may include polymers, coatings, oil and grease lubricants, and ferrous and nonferrous metals.

d) Determine the applicable environmental and operational stressors and their duration as defined in 6.4, described as follows:

   1) *Temperature*. Establish an ambient temperature range. Determine the temperature rise over ambient and identify potential for hot spots for equipment parts during operation and cycling.

   2) *Radiation*. Establish the radiation environment (predominantly, gamma and neutron), including cumulative dose, dose rate, and radiation hot spots.

   3) *Humidity / water*. Determine the presence and severity of humidity and water from both internal and external sources.

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4) *Electrical*. Determine the electrical stressors (magnitudes and durations) that the equipment may experience during normal design life. The electrical stressors should be evaluated for

   i) Normal operating conditions
   ii) Plant switching, cycling, and test conditions

   For example, the nature of electrical stressors may include voltages and currents involving dc, low-frequency (50–60 Hz) signals, slow-switching transients, fast transients of lightning variety, or superposition of more than one of these voltages and currents

5) *Mechanical*. Determine the mechanical stressors that the equipment may experience during normal design life. Evaluate for

   i) Normal design static loads
   ii) Seismic loads
   iii) Vibration loads

6) *Chemical / electrochemical / contamination*. Identify and evaluate chemicals, electrochemical conditions, contaminants, and other atmospheric conditions that might contribute to aging.

e) After materials have been identified, relevant data have been collected, and stressors have been established, make use of the reference tables to determine potential aging mechanisms. These mechanisms involve behavior of microstructures and physical and chemical processes. Although detailed understanding of aging mechanisms at all degradation sites within the equipment boundary of interest may not be practical, increased knowledge of mechanisms to the extent possible is generally useful for an enhanced understanding of aging effects and for an appropriate choice of monitoring methods.

f) Make use of the third column of the tables to help determine aging effects. Knowledge of aging effects is important for monitoring and condition assessment, as discussed in Clause 6 and Clause 7 of this guide.

g) Use column four of the tables to help identify parameters to be monitored and to identify inspection, surveillance, and monitoring methods. Select cost-effective inspection, surveillance, and monitoring methods as appropriate.

h) Generate a database by establishing baseline signatures and trend performance parameters on a periodic basis, as discussed in Clause 7 of this guide.

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Table A.1—Polymers—aging effects

Stressors (see Note 1)	Aging mechanisms	Aging effects	Candidate monitoring method for aging effects (see Note 2)
Thermal Ambient temperature Temperature gradients Self-heating due to operation (e.g., ohmic heating) Temperature cycling	Free radical formulation by hydroperoxide breakdown Auto-oxidation acceleration (oxidative degradation) Scissioning / cross-linking Flow / creep acceleration Migration and evaporation of plasticizers / chemicals Volatility of chemicals Offgases (e.g., Cl_2, SO_2) Changes in morphology / crystallization	Changes in dielectric properties Embrittlement / hardening Reduction in elongation to rupture Cracking Softening / reduced strength Changes in physical dimensions/ delamination Adverse chemical reactions Reduced voltage withstand capability Increased leakage current	Equipment temperature Thermocouple Thermal-scanning infrared Color-coded indicators Touch / feel Parameters to monitor / techniques Dissipation factor Insulation resistance Partial discharge Gas ionization (see Note 3) Visual Hardness / resistance to indentation Sample analysis (see Note 3) Elongation to rupture Antioxidant consumption Oxidative induction temperature Infrared spectroscopy Nuclear magnetic resonance (NMR) spectroscopy Gas / liquid chromatography Differential scanning calorimeter Exothermic for temperature history Time-domain spectrometry (TDS) (see Note 3)
Radiation Gamma (mostly) Neutron (some)	Cross-link / scissioning Free radial formation by radiation-polymer interaction Auto-oxidation (oxidative degradation) Scissioning / cross-linking	Temporary change in dielectric properties Permanent change in dielectric properties Embrittlement / hardening Reduction in elongation to rupture Cracking Softening / reduced strength Increased leakage current Reduced voltage withstand capability	Same as thermal Dosimetry

NOTES

1—Elevated temperatures, gamma and beta radiation, and other factors due to design basis (DBE) conditions are not considered as age related.

2—The items listed are subcategories of typical monitoring methods.

3—Some of these monitoring methods may still be under development for commercial use.

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Table A.1—Polymers—aging effects (continued)

Stressors (see Note 1)	Aging mechanisms	Aging effects	Candidate monitoring method for aging effects (see Note 2)
Humidity Ambient relative humidity Condensation	Vapor diffusion Surface ionization / distribution of electric field Absorption of water	Changes in dielectric properties Reduced voltage withstand capability Partial surface discharge / corona Decomposition products / gases Arc tracking Swelling Delamination Increased leakage current	Relative humidity measurement Parameters to monitor / techniques Dissipation factor Insulation resistance Partial discharge Leakage current Polarization index Visual Feel Moisture content Time-domain reflectometry (TDR) (see Note 3)
Water External Internal	Absorption of water Dendritic formation (treeing) in presence of electrical stresses (normally only in medium- and high-voltage cable)	See humidity effects	See humidity monitoring methods
Electrical 50–60 Hz ac Direct current Switching transients Fast transients Arcing	Partial discharge / corona Arcing Temperature rise Ozone Surface electrical stress	Dielectric losses Decomposition products / gases Reduced voltage withstand capability Embrittlement / hardening Softening / reduced strength Surface properties change Carbon formation of surface Arc tracking	Transient voltage monitoring Equipment temperature Insulation resistance Ozone monitoring Visual Feel
Mechanical Static loading Bending Tensile Shear Compressive Dynamic loading Normal Overload Cycle loading	Creep Compressive set Tensile loads Shear loads Torsional loads Fatigue Electromagnetic and electromechanical forces	Changes in dimensions Work hardening Change in strength Cracking Generation of wear products Changes in alignment or clearance Changes in dielectric properties / reduced voltage withstand capability	Parameters / available techniques Dissipation factor Insulation resistance Partial discharge Visual inspection Dimensional measurement Bearing noise, vibration, and compression set Bearing temperature

NOTES

1—Elevated temperatures, gamma and beta radiation, and other factors due to design basis (DBE) conditions are not considered as age related.

2—The items listed are subcategories of typical monitoring methods.

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Table A.1—Polymers—aging effects (continued)

Stressors (see Note 1)	Aging mechanisms	Aging effects	Candidate monitoring method for aging effects (see Note 2)
Vibration Seismic Plant-induced — Normal — Abnormal	Fatigue Wear Tensile loads Shear loads Torsional loads	Separation of polymer from other materials such as printed circuits Changes in alignments and clearances Wear and fretting (reduction of surfaces) Elongation, dimensional changes	Visual inspection Accelerometer Vibrations / frequency monitoring Bearing temperature
Chemical Boric acid Oil Trisodium phosphate Hydrazine Sodium hydroxide Cleaning fluids	Disturbance of electric field distribution Corrosion Contamination / deposits Direct chemical reaction at elevated temperatures	Changes in dielectric properties Reduced voltage withstand capability Change in surface conditions Increased leakage current Corrosion wastage	Parameters to monitor / techniques Dissipation factor Insulation resistance Partial discharge pH Test Water chemistry Visual
Electrochemical	Oxidation	Corrosion at polymer / metal interfaces	Visual Water chemistry Dimensional measurement
Contaminants Dust / dirt Wear products	Disturbance of electric field distribution Wear	Reduced voltage withstand capability Increased leakage current Prevents leakage current Prevents contact closure Improper mechanical operation	Parameters to monitor / techniques Dissipation factor Insulation resistance Partial discharge Leakage current Visual inspection

NOTES

1—Elevated temperatures, gamma and beta radiation, and other factors due to design basis (DBE) conditions are not considered as age related.

2—The items listed are subcategories of typical monitoring methods.

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Table A.2—Lubricants—aging effects

Stressors (see Note 1)	Aging mechanisms	Aging effects	Candidate monitoring method for aging effects (see Note 2)
Thermal Ambient temperature Temperature rise Temperature gradients Temperature cycling	Oxidative degradation of oil Thermal degradation of oil Evaporation of chemicals Thermal degradation of grease Polymerization Reduced film strength	Viscosity changes Varnish formation Change in chemical properties Loss of lubricant Formation of gases / polymers Softening / flow Hardening / increased drag Oil separation Increased volatility / evaporation Color change Increased wear	Visual (see Note 3) Oil viscosity (see Note 4) Grease consistency (see Note 5) Lubricant analysis (see Note 6) Temperature (see Note 7) Lubricant level Pressure / flow Odor Feel (see Note 8)
Radiation Gamma (mostly) Neutron (some)	Oxidative degradation Polymerization Scission Cross-linking Outgassing	Change of state Solidification Consistency change Color change Breakdown of chemical bonds Increase penetration Odor change Increased acidity Reduced lubricating life	See methods for thermal stressors Radiation dosimetry

NOTES

1—Elevated temperatures, gamma and beta radiation, and other factors due to design basis (DBE) conditions are not considered as age-related.

2—The items listed are subcategories of typical monitoring methods.

3—Visual: color comparison, color change, solid content in oil, foreign matter in grease.

4—Oil viscosity (see ASTM D445-97 [B4]).

5—Grease consistency, worked penetration (see ASTM D217-97 [B3]).

6—Lubricant analysis, infrared analysis, ash content (see ASTM D128-94a [B2], ASTM D482-95 [B5], and ASTM D874-96 [B6]), atomic absorption spectroscopy, x-ray dispersion, sludge formation, water droplets, and gas chromatography.

7—Temperature monitoring, thermocouples, and infrared thermal scanning.

8—Feel: comparison with new lubricant, grittiness, solidifications.

9—Water content (see ASTM D1744-92 [B1]), chemical analysis (see ASTM D128-94a [B2]).

10—Sound: increased noise, unusual sounds, grinding, rattling in bearings.

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Table A.2—Lubricants—aging effects (continued)

Stressors (see Note 1)	Aging mechanisms	Aging effects	Candidate monitoring method for aging effects (see Note 2)
Humidity Ambient relative humidity Water	Oxidative degradation Dilution	Reduction of viscosity Loss of lubricity Sludge formation Corrosion of metals Clogging of filter Color change Increased foaming Displacement of lubricant Rust formation Increased volatility	See methods for thermal stressors Relative humidity measurement Water content (see Note 9) Acidity
Electrical 50–60 Hz ac Direct current Fast transients Arcing	Temperature rise Arcing Ozone Partial discharge / corona	See effects for thermal stressors, plus oxidation / hardening	See methods for thermal stressors Relative humidity measurement Water content (see Note 9) Acidity
Mechanical Static loading Dynamic load Normal overloads Vibration Seismic Cycling	Displacement Breakdown of film strength Frothing / foaming Heating through compression or high velocity Creep / flow	Reduction in volume Increase wear Sludge Increased temperature Wear products Increased leakage Change in vibration pattern Peening of bearings	See methods for thermal stressors Magnetic methods Sound (see Note 10)

NOTES

1—Elevated temperatures, gamma and beta radiation, and other factors due to design basis (DBE) conditions are not considered as age-related.

2—The items listed are subcategories of typical monitoring methods.

3—Visual: color comparison, color change, solid content in oil, foreign matter in grease.

4—Oil viscosity (see ASTM D445-97 [B4]).

5—Grease consistency, worked penetration (see ASTM D217-97 [B3]).

6—Lubricant analysis, infrared analysis, ash content (see ASTM D128-94a [B2], ASTM D482-95 [B5], and ASTM D874-96 [B6]), atomic absorption spectroscopy, x-ray dispersion, sludge formation, water droplets, and gas chromatography.

7—Temperature monitoring, thermocouples, and infrared thermal scanning.

8—Feel: comparison with new lubricant, grittiness, solidifications.

9—Water content (see ASTM D1744-92 [B1]), chemical analysis (see ASTM D128-94a [B2]).

10—Sound: increased noise, unusual sounds, grinding, rattling in bearings.

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Table A.2—Lubricants—aging effects (continued)

Stressors (see Note 1)	Aging mechanisms	Aging effects	Candidate monitoring method for aging effects (see Note 2)
Chemical Boric acid Sodium hydroxide Ammonia Trisodium phosphate Hydrazine	Reacts with lubricant Additives Reduce lubricity Direct oxidative degradation at elevated temperatures and radiation	Corrosion of metals Foaming Sludge formation Change in viscosity Softening of grease Change in volatility	See methods for thermal stressors Water (see Note 9) Acidity
Contaminants Dust / dirt Wear products	Wear / erosion Abrasion Mechanical interference Reaction with lubricant Increased viscosity Sludge formation Displacement of lubricant	Reduced efficiency Increased operating temperature Clogged filters Reduced cooling of “hot spots” Reduced life of components Change in viscosity	See methods for thermal stressors Magnetic method Sound (see Note 10)

NOTES

1—Elevated temperatures, gamma and beta radiation, and other factors due to design basis (DBE) conditions are not considered as age-related.

2—The items listed are subcategories of typical monitoring methods.

3—Visual: color comparison, color change, solid content in oil, foreign matter in grease.

4—Oil viscosity (see ASTM D445-97 [B4]).

5—Grease consistency, worked penetration (see ASTM D217-97 [B3]).

6—Lubricant analysis, infrared analysis, ash content (see ASTM D128-94a [B2], ASTM D482-95 [B5], and ASTM D874-96 [B6]), atomic absorption spectroscopy, x-ray dispersion, sludge formation, water droplets, and gas chromatography.

7—Temperature monitoring, thermocouples, and infrared thermal scanning.

8—Feel: comparison with new lubricant, grittiness, solidifications.

9—Water content (see ASTM D1744-92 [B1]), chemical analysis (see ASTM D128-94a [B2]).

10—Sound: increased noise, unusual sounds, grinding, rattling in bearings.

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Table A.3—Metals-aging effects

Stressors (see Note 1)	Aging mechanisms	Aging effects	Candidate monitoring method for aging effects (see Note 2)
Thermal Ambient temperature Temperature gradients Self heating due to operation (e.g., ohmic heating) Temperature cycling	Surface oxidation Creep Temperature rise	Loss of thermal conductivity Change in mechanical strength / properties Embrittlement Deformation Material transfer Loss of electrical conductivity Change in magnetic properties	Equipment temperature Thermocouple Resistance temperature detector (RTD) Thermocouple Infrared pyrometry Color-coded indicators Visual Touch Current monitoring (resistance change)
Radiation Neutron	Modifies crystalline structure	Changes in electrical and mechanical properties (usually insignificant)	Visual Dosimetry See methods for thermal stressors
Humidity Condensation	Corrosion (including galvanic) Electrolysis Arcing Oxidation	Changes in electrical properties Dimensional changes Changes in air gaps Physical changes	Relative humidity measurement Visual Feel
Water External Internal	Electrical conduction Oxidation Erosion	Changes in electrical properties Changes in mechanical properties Transports undesirable contaminants Change in dimensions	Visual Monitor changes in electrical properties such as contact resistances
Electrical	Arcing Temperature rise Electromagnetic field effects Induction Magnetostriction Electrochemical corrosion Ozone Electrochemical forces	Pitting / corrosion Change in electrical, magnetic, mechanical properties Elevated temperatures Production of gases / ozone / decomposition products Forms plastic film over contacts	Visual Pitting Corona Voltage and current monitoring Resistivity of applicable conductors of contacts Oscilloscope Audio Gas chromatography for special applications

NOTES

1—Elevated temperatures, gamma and beta radiation, and other factors due to design basis (DBE) conditions are not considered as age related.

2—The items listed are subcategories of typical monitoring methods.

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Table A.3—Metals-aging effects (continued)

Stressors (see Note 1)	Aging mechanisms	Aging effects	Candidate monitoring method for aging effects (see Note 2)
Mechanical Static loading Applied load Compressive Dynamic loading Cycling Switching Impact	Creep Fatigue Wear Erosion Tensile loads Shear loads Torsional loads	Changes in dimensions Changes in strength Cracking Work hardening Generation of wear products Reduced spring function	Visual Accelerometer Dimensional measurements Nondestructive examination Eddy current Ultrasonic Magnetic particle Gas chromatography of lubricants to determine sources of wear products
Vibration Internally generated Externally generated Seismic	Fatigue Wear Tensile loads Shear loads Torsional loads	Changes in dimensions Changes in strength Cracking Generation of wear products	Same as mechanical
Chemical Boric acid Trisodium phosphate Sodium hydroxide Cleaning fluids Hydrazine	Corrosion Oxidation / reduction Dezincification Hydrogen embrittlement Intergranular corrosion, galvanic corrosion	Changes in electrical and mechanical properties Modifies condition of contacting surfaces Cracking, velocity, sponge, pitting, leaching	Visual Measure electromotive force (galvanometer) Wet chemistry Gas chromatography to identify chemicals pH test
Contaminants Dust / dirt Wear products	Wear / erosion Abrasion Mechanical interference	Reduced contact integrity Reduced mechanical performance Introduce new conduction paths Metal transfer Temperature rise	Visual Electrical characterization Chemical analysis Gas chromatography to identify chemicals X-ray diffusion

NOTES

1—Elevated temperatures, gamma and beta radiation, and other factors due to design basis (DBE) conditions are not considered as age related.

2—The items listed are subcategories of typical monitoring methods.

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Annex B

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Monitoring of environments

NOTE—The information in this annex is provided for the sole purpose of illustrating the aging assessment methodology in the body of the guide and does not represent an IEEE or industry position on any of the equipment or systems that are addressed.

B.1 Introduction

As discussed in Clause 4 of this guide, environmental stressors may affect materials in Class 1E electrical equipment. Knowing the environment and its effect on equipment is essential for aging assessment of equipment. This section deals with elements of an environmental monitoring program including factors that influence environment, identification of plant areas and equipment to be monitored, identification of environmental stressors, and techniques to accomplish the in-plant monitoring program.

B.2 Environmental stressors

The significant environmental stressors to be considered in evaluating and predicting the useful life of Class 1E electrical equipment are as follows:

a) Temperature
b) Radiation (gamma)
c) Humidity
d) Chemical
e) Exposure
f) Dust / dirt

For each environmental stressor, a material degradation threshold value should be determined for each type of equipment. The material degradation threshold value is defined as that environmental parameter value that does not contribute significantly to the degradation of the component material. If the worst-case environmental parameter value for a specific area is lower than the material degradation threshold value, no further evaluation of that environmental stressor's effect on the component is needed.

B.2.1 Temperature

The environmental stressor that influences the service life of most electrical equipment is temperature. It is necessary to monitor the temperature or to obtain temperature records so that the Class 1E equipment can be assessed, as explained in Clause 6 of this guide. The temperature data may identify the need for preventive or corrective actions to preclude an early equipment failure and / or shorten its useful life. Self heating is also a temperature concern along with hot spots and heat rise due to process or energized equipment.

Temperature in some areas inside a nuclear power generating station may vary seasonally and with plant operating modes. The periods of lower / higher temperature may provide a basis for reassessing the equipment design / qualified life.

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B.2.2 Radiation

Radiation-induced effects are typically produced only by radiation doses greater than the threshold dose; i.e., the lowest dose that causes a measurable, permanent change in a specified physical property of a material.

Radiation-aging considerations include the following:

a) The aging dose for the equipment should be determined on the basis of expected service environment.

b) Materials should be investigated for potential synergistic effects that result from two or more stresses acting together.

c) Equipment materials should be investigated to determine whether dose-rate effects are known to be significant. Radiation resistance is typically determined with Co-60 gamma radiation to dose rates of 1–1000 krad/h (10–10 000 Gy/h), a value greatly exceeding normal service environments for organic materials in nuclear safety equipment.

d) Neutron radiation is generally not considered in the aging degradation of Class 1E equipment, since Class 1E equipment items are not located in close proximity to a neutron radiation source, i.e., fuel. An exception to this may be an area directly above the reactor head.

B.2.3 Humidity

There is no generalized model for evaluating humidity-caused degradation. Temperature cycling tends to exacerbate humidity effects by causing condensation and subsequent transport of moisture to internal regions of equipment.

B.2.4 Chemical exposure

As with humidity, prolonged chemical exposure, particularly in combination with other stresses, can be detrimental to electrical equipment. Chemicals may be boric acid, oils and grease, and other relatively common materials. A monitoring program should include inspection in potentially affected areas.

B.2.5 Dust/dirt

Dust and dirt do not affect enclosed or sealed devices. Dust and dirt may affect open or exposed electrical equipment such as relay contacts, switches, terminal blocks, and circuit breakers. Physical inspection during periodic surveillance is one of the ways to monitor and note dust and dirt accumulation on Class 1E equipment. Removal of dust and dirt during this periodic surveillance can increase equipment reliability and reduce degradation.

B.3 Environmental monitoring program

B.3.1 Plant areas to be monitored

The first step in preparing a monitoring program is to identify and locate plant areas where Class 1E electrical equipment being evaluated is installed. Some areas of the plant may be of particular concern for a monitoring program. These areas include confined spaces such as vaults with limited ventilation and / or heat sources, equipment located directly above the reactor head, and equipment susceptible to process temperature conditions.

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B.3.2 Plant survey

A plant survey should be conducted in each identified area. The purpose of the survey is to identify

a) Areas where environmental stressors require monitoring

b) Confined areas and heat sources affecting the equipment

c) Areas and equipment where special monitoring techniques are required

The plant survey should include a review of drawings, interviews with plant personnel, and a plant walkdown and should identify areas affected by plant status or seasonal changes.

During the walkdown, special attention should be paid to the location and installation of equipment. Look for wrapped cable trays and equipment housed in cabinets without proper ventilation.

B.3.3 Compilation of available data

A thorough review of available plant data should be conducted for equipment and spaces. Key elements of the review should include the following:

a) Heating, ventilating, and air conditioning (HVAC) design parameters for each area

b) Plant modifications having favorable or adverse effects on the environment; results of previous environmental surveys, including health physics data, preoperational test data, and equipment qualification files

c) Equipment failures that may have been influenced by the environment

d) External effects such as plant status, HVAC status, and seasons that affect the environment

For example, manufacturer's data on heat rise due to internal heat generation in equipment (e.g., a solenoid coil) is usually given with reference to an ambient temperature. The actual heat rise of the equipment installed in a location with a different ambient temperature should be obtained from the manufacturer, or otherwise determined.

B.3.4 Developing the monitoring program

The techniques and technology of environmental monitoring as applicable to a nuclear power generating station are summarized in the following paragraphs.

During normal operation, surveys with hand-held instruments provide a convenient approach. Hand-held instruments are available for temperature, radiation, and humidity measurements.

Temperature monitors include thermistor, thermocouple, resistance temperature detectors (RTDs), and infrared type. Thermistors, thermocouples, and RTDs can be used to measure ambient air temperature and equipment surface temperature. An infrared (IR) spectroscope measures the infrared radiation emitted by objects to determine temperature. The IR scope takes much less time to make an accurate reading and does not require contact with the object to be measured. The IR scope also allows the user to quickly scan and locate hot spots.

Plant personnel routinely perform radiation surveys using hand-held instruments. Assuming the data is part of the plant record, the data may be retrieved to determine an integrated dose to equipment. A means of speeding up radiation walkdowns is to place Universal Product Code (UPC) bar codes in selected locations

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that can be read by a sensor while simultaneously determining the dose rate, both of which are stored in memory.

Humidity measurements also lend themselves to a walkdown with hand-held instruments. This may have to be done seasonally to determine any variation. Areas of high humidity should be investigated for signs of condensation.

Chemical exposure monitoring is best performed by physical inspection of suspected areas.

Plant areas and equipment that require lengthy monitoring periods, or are inaccessible during plant operation, would require the use of remote data-gathering techniques. Careful attention should be given to the number and placement of monitors in an area. In addition to area ambient temperature, internal and surface temperature is important for some equipment (wrapped cables and equipment in cabinets). Enough monitors should be placed to obtain sufficient data.

B.3.5 Monitoring period

The frequency and duration of the monitoring program should take these following items and events into account because they may influence the data being gathered:

a) Seasonal effects

b) Changes in ventilation

c) Status of HVAC

d) Construction activities

e) Plant operations and cycles

B.3.6 Review of results and storage of data

The results of the monitoring program should be reviewed to ensure that the data accurately reflects the stressors being monitored. This may require changes in monitor location or follow-up monitoring to verify results.

The results of the environmental monitoring program should be retained as part of the equipment life assessment evaluation.

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Annex C

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Condition monitoring

NOTE—The information in this annex is provided for the sole purpose of illustrating the aging assessment methodology in the body of the guide and does not represent an IEEE or industry position on any of the equipment or systems that are addressed.

C.1 Introduction

Condition monitoring is the observation, measurement, or trending of condition indicators with respect to some independent parameter (usually time or cycles) to indicate the current and future ability to function within acceptance criteria. The purpose of this annex is to provide a list of state of the art condition monitoring techniques that may be used to support aging assessment and mitigation. Much study and experimentation in this area has been conducted and continues to occur. Because the technology for condition monitoring is continuing to be developed, it is anticipated that this annex will be updated as IEEE Std 1205 is periodically updated.

Condition monitoring is used to determine and predict the physical and operating status of equipment. The condition of a limiting weak link part is used as an indicator to determine the overall condition of the equipment. The condition of the weak link material or part is ascertained by comparing some age-dependent or trendable material property or other observable parameter to a baseline value (usually the value when new) or an end condition (determined from the acceptance criteria).

C.2 Condition monitoring considerations and characteristics

A valid aging trendable parameter or property (also called a condition indicator) needs to be identified in order for condition monitoring to be effective. Selection of the trendable parameter or property should consider

— Practicality and ease of the test measurement

— Destructive/intrusive vs. nondestructive/nonintrusive nature of the method

— Sensitivity to aging

Ideally, the property or parameter would also have

a) Relatively uniform changes with age

b) Changes with age large enough in magnitude to establish differences in the degree of aging

c) Ability to be tested or measured

d) Reproducible results

e) Confidence in establishing intervals of time between testing that assure continued functionality (as defined by the acceptance criteria) during the entire duration of this interval (and during the postaccident operating time for EQ equipment)

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C.3 Available condition monitoring techniques

An appropriate aging trendable parameter can be determined based on the type of equipment or weak link part or both. An example of equipment type is rotating machinery, where a useful trendable parameter might be vibration or lubricant wear product concentration. An example of a potentially limiting part is electrical insulation where a parameter such as hardness, dielectric strength, or tensile strength could be used for condition monitoring. Table C.1 summarizes candidate condition monitoring methods by equipment type and limiting part.

Table C.1—Candidate condition monitoring methods

Equipment type or limiting part	Candidate condition monitoring methods	Physical principle
Rotating machinery	Vibration monitoring and analysis of frequency and displacement (amplitude)	As the bearings of rotating machinery wear, the shaft has more radial freedom of movement, which results in increased vibration (both displacement and acceleration).
	Lubricant wear product analysis	As the bearings of rotating machinery wear, wear products accumulate in the lubricant. Even if the lubricant is replaced at certain wear product or contaminant thresholds, records of total integrated wear product concentrations can be used to trigger bearing replacement.
Motor-operated valves	Torque cartridge on spring pack and strain gauge on yoke arm	As valve stem / disk assembly and stem movement mechanism wear with age, the result is a change in the spring pack torque and strain gauge readings.
	Torque thrust cell (plate bolted on yoke below actuator)	As valve stem / disk assembly and stem movement mechanism wear with age, the result is a change in the torque readings at the thrust cell.
Heat emitters (e.g., bearings, fuses, normally energized solenoid valves, or motors)	Embedded temperature sensors for direct temperature readout	High or rising temperature is likely indicative of excessive deterioration of bearings and insulation systems.
	Infrared thermography	Indirect readout of temperature based on correlation to energy emitted in the infrared spectrum.
Pressure-retaining components (e.g., pressure transmitters)	Visual inspection	Visual evidence of crack indication.
	NDT (e.g., dye penetrant, acoustic, x-ray)	Indirect but potentially more sensitive means for detecting crack indications.
	Leak detection	Detection of contained gas or fluid outside of pressure vessel is indicative of integrity failure.

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Table C.1—Candidate condition monitoring methods (continued)

Equipment type or limiting part	Candidate condition monitoring methods	Physical principle
Motor / generator electric insulation systems	Current signature analysis	Magnitude of current for a given applied voltage and load provides information on aging effects manifested as overheating, turn-to-turn faults, high resistance, unbalanced stator currents, and high stator currents.
	DC high-potential step test	Assessment of condition of groundwall insulation through application of high-voltage dc in increasing increments. As windings are stressed with increasing voltage, measurements are made of the increasing leakage current. A nonlinear increase is indicative of an aging effect related to a ground fault, increase in insulation voids, loose bracing, or partial discharge.
	Partial discharge (via electromagnetic [EM] or acoustic detection)	Detection of voids within the insulation system. Voids are created and grow as a function of age and are indicative of insulation deterioration. Partial discharge is the corona effect that takes place in a void separating two areas of high potential.
Electric cable insulation	Visual inspection	Visual evidence of discoloration, corrosion, cracking, hardening, swelling, or jacket separation from insulation is indicative of aging.
	Compressive modulus (indenter)	Hardening of insulation jacket is correlated to aging of interior insulation.
	Partial discharge (via EM or acoustic)	Detection of ionized void formation is indicative of pending insulation failure (for medium-voltage and above-shielded cables).
	Void size and density growth rate via acoustic microscopy	Monitoring of microscopic void growth and void density increases caused by polymer breakdown from thermal, thermoxidative, and radiation induced aging. Proximity to void size and density at threshold of limiting value is a quantitative indicator of remaining insulation life.
	Time-domain reflectometry	Detection of age-related oxidation / corrosion of termination and discontinuity formation in insulation.
	Insulation density	Reductions in density are indicative of polymer breakdown from thermal and radiation aging.
	Oxidation induction time (OIT)	Estimation of remaining thermal life of polymer through measurement of antioxidant concentration.

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Table C.1—Candidate condition monitoring methods (continued)

Equipment type or limiting part	Candidate condition monitoring methods	Physical principle
Electric cable insulation	Fourier transform infrared (FTIR)	Detection of oxidation (carbonyl group) within polymer; correlates aging with changes in polymer chemical structure.
	UV spectroscopy	Detection of phenyl groups and evaluation of antioxidant content of PE insulation.
	Gel content	Measurement of induction time for change in gel content and swell ratio for use in establishing extent of cross-linking and / or chain scission reactions within the material.
	Plasticizer content	Measurement of percent plasticizer (reduction in volatility) and estimate of remaining life.
	Nuclear magnetic resonance (NMR) / electron spin resonance (ESR)	NMR—characterization of water and polymer reaction during water tree growth; ESR—characterization of free radicals.

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Annex D

(informative)

Equipment and system examples

NOTE—The information in this annex is provided for the sole purpose of illustrating the aging assessment methodology in the body of the guide and does not represent an IEEE or industry position on any of the equipment or systems that are addressed.

D.1 Reactor protection system

The reactor protection system (RPS) prevents exceeding specified plant safety limits by automatically de-energizing the power sources to the control-rod drive mechanisms using the reactor trip system (RTS). The RPS also actuates emergency equipment in the event of a loss of primary or secondary system coolant by using the engineered safety features actuation system (ESFAS).

The parameters that actuate the RPS vary, depending on plant type. In this example for a pressurized water reactor (PWR), actuation of the RPS to insert the control rods is initiated by one of the following parameters:

a) High reactor power
b) Loss of power to reactor coolant pumps
c) High temperature, hot leg
d) High reactor coolant system pressure
e) Low reactor coolant system pressure
f) Turbine trip
g) Overtemperature delta temperature
h) Overpower delta temperature
i) Reactor trip discharge volume high water level
j) Low feedwater flow
k) Anticipatory loss of main feedwater
l) Manual operator action
m) Safety injection signal actuation
n) Turbine stop valve closure
o) Turbine control valve fast closure
p) Reactor vessel low water level
q) Main steam line isolation
r) Main steam line high radiation
s) Main condenser low vacuum
t) Mode switch in shutdown
u) Nuclear overpower based on reactor coolant flow and axial imbalance
v) Low steam generator level
w) High containment pressure

D.1.1 Evaluation boundaries

The RPS includes the sensors, cables, signal-conditioning electronics, and processing logic devices that are required to initiate a reactor shutdown and actuate the emergency equipment.

To facilitate the aging assessment, the RPS is divided into logical functional building blocks that are easily recognizable. For this example, the functional blocks or system subassemblies are

— Sensors
— Interfaces

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— Cables
— Signal conditioning electronics
— Processing logic devices

It would be possible to subdivide each type of sensor, electronics, or relay into smaller sections to help identify those materials or subcomponents that are most likely to experience aging degradation. For this example, the sensors, signal conditioning electronics and processing logic devices, exclusive of cables and terminations, will define the evaluation boundaries.

D.1.2 Identify safety functions

The RPS has two primary functions. The first function of the RPS is to prevent exceeding specified plant safety limits by automatically de-energizing the power sources to the control-rod drive mechanisms, thereby allowing the control rods to insert into the core. This function is accomplished by the RTS. The second function of the RPS is to actuate emergency equipment in the event of a loss of primary or secondary system coolant. This function is accomplished by the ESFAS.

Sensors (transducers) are devices used to transform a parameter such as temperature or pressure into an equivalent electrical signal that can be further interpreted and acted on by other circuitry. Temperature sensors may be resistance temperature detectors (RTDs). Sensors for pressure, flow, and level measurements are primarily pressure or differential pressure transmitters. Reactor power is measured with compensated ion chambers. Other sensors include limit switches or contacts to detect position and current transformers for the measurement of current. In this example, only pressure transmitters are assessed. A similar approach would be followed for the other types of sensors.

Signal conditioning electronics is a title for a variety of functional analog and/or digital circuitry that, as a group, energize and interpret the significance of the sensor signal. Signal conditioning electronics includes instrument power supplies, buffer amplifiers, signal amplifiers, bistables, and test modules.

The processing logic devices are relays connected in various matrices to provide the reactor trip or ESFAS logic. In this example, the relay system consists of some 750 relays with 4000 contacts housed in 14 cabinets.

NOTE—Other designs utilize solid-state techniques (digital), which reduce the number of relays and cabinets from the all-relay system of this example.

D.1.3 Equipment locations

Sensors are often located close to, if not in intimate contact with, the process parameter that is being monitored. Sensors that monitor nuclear steam supply system parameters are, by and large, located in the containment building. Some sensors are located on the reactor loop piping, reactor vessel, pressurizer, coolant filter media, and steam generators. Sensors that monitor steam generator secondary-side parameters are located in the main steam valve, auxiliary, and turbine buildings.

Signal conditioning electronics and processing logic devices are located in the control room or the instrument rack room. Some sensors contain built-in signal conditioning circuitry to compensate for the very long cable lengths required to reach the instrument racks. The signal is further processed within the instrument racks.

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D.1.4 Service conditions

Equipment qualification records, Annex A of this guide, and aging research performed by the Electrical Power Research Institute (EPRI) and Nuclear Regulatory Commission (NRC) were reviewed to determine the service conditions applicable to the RPS.

Sensors

Temperature and moisture are the two most prominent stressors for sensors. These stressors lead to drift, out-of-calibration conditions, and circuit failures primarily by degrading insulation and causing corrosion of electrical connections and mechanical linkages.

Processing logic devices

Relays and similar processing logic devices are primarily degraded by temperature, foreign material, and contact surface degradation that causes open circuits and failure to close or failure to open.

Determination of the environmental service conditions for temperature and moisture at the sensor locations is needed to establish if service conditions are equal to or less than the conditions utilized for qualification testing. Similarly, ambient temperatures of the processing logic devices are needed. These temperatures should be found in records of periodic surveillance measurements of environmental / ambient conditions at various locations in the plant during periods of operation. Preventive maintenance records for batteries may show when equalizing charges were performed, the voltage of the equalizing charge, and the duration. Identification of this voltage is important to assure that process logic devices (relays) were not subjected to overvoltage conditions that would shorten the expected service life.

Stessors, aging mechanisms, and aging effects are listed in Table C.1 for sensors and processing logic devices. Signal conditioning electronics were not evaluated further because of their service life limitation (15–20 years) and because of obsolescence (as it affects spare parts and repair support).

D.1.5 Materials of construction

Sensors

Organic material is contained in gaskets, insulating material, and miscellaneous plastic components, including components within the signal conditioning circuitry, if used. Inorganic material is contained in some sensor bodies, internal conductors, and signal conditioning circuitry (semiconductors), if used.

Processing logic devices

Organic material is contained in insulating materials, miscellaneous internal plastic components, and external components such as dust shields, sockets, and terminal connection barriers. Inorganic material is contained in the contacts and contact support assemblies, conductors, and external connections.

D.1.6 Identify and assess significant aging effects

The approach for identifying aging effects was to review the following six sources of information:

— The material in Annex A
— The plant EQ records
— Aging research performed by EPRI and NRC
— License event reports (LERs), an operational database maintained by the NRC

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— Equipment Performance and Information Exchange System (EPIX) records, an operational database maintained by the Institute of Nuclear Plant Operators (INPO)

— Plant maintenance records (also reviewed to further identify failure modes that are occurring)

A search of LERs and EPIX records revealed a history of failures dating back to 1976. Many of the failures were related to design deficiencies, which were subsequently resolved as noted in the following paragraphs.

Many of the failures were associated with normally energized dc relays, with the primary cause of failure attributed to higher than expected ambient temperature or due to a higher than expected self-heating effect. Self-heating can be caused by exceeding design operating voltage, e.g., operating at 132 V rather than 125 V. Sustained overvoltage may occur during plant shutdown when batteries are being charged. Although these failures may have resulted from misapplication, they nonetheless resulted in aging degradation.

Characteristics critical to the performance of RPS components were reviewed and evaluated to identify those that are expected to be significantly affected by the aging effects identified in D.1.6. Those that have the most limiting influence were identified as limiting age-related critical characteristics.

Sensors

The limiting age-related critical characteristics for sensors are electrical insulation resistance and material wear of mechanical parts due to operational cycling. The most common failure mode reported in databases for pressure transducers is drift (55% of the total number of problems are with pressure transducers). Aging degradation accounts for about 13% of the failures, with the most frequently reported aging-related cause being related to normal operation and environmental conditions.

Processing logic devices

The limiting age-related critical characteristics for relays are insulation resistance and erratic operation. In terms of failure history based on a review of the public databases up to 1986, a total of 138 relay failures have been reported at 16 plants. This represented a total operating time of 1.25 million hours. Most of these failures (90) have occurred since 1984 and may be age-related. The most common failure mode is an open condition in relay coils (68%) followed by binding of relay internals (22%). Historically, these problems have been primarily attributed to aging degradation (33%), overheating (27%), dirt accumulation (11%), and unknown causes (19%).

NOTE—If this were a plant-specific application, the EQ records should be referred to at this point.

D.1.7 Aging management

Monitoring of parameters

Parameters to be observed or measurable quantities are presented in Table D.1. Some of those, such as insulation resistance degradation, are a direct measurement of the aging effect, while others, such as functional testing, provide an indirect indication. Also, some observable parameters are typically obtained by emerging technologies rather than being generally measured at nuclear plants; these are indicated by an asterisk (*). Presently, response time testing, functional checks, channel calibrations and operational tests are performed on a periodic basis. The results from these tests and surveillance provide information that can be analyzed to provide an early indication of aging degradation.

In parallel with monitoring parameters, using established analysis techniques and the accumulated knowledge of the equipment's past performance can be useful with respect to obtaining insights as to how long a parameter should be monitored or which parameters should be monitored.

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Table D.1—Aging management observable parameters

Component	Limiting age-related critical characteristic	Observable parameters
Sensors	Electrical insulation resistance	Insulation resistance Functional checks Instrument calibration Visual inspection of insulation integrity Dissipation factor* Characteristic impedance*
	Material wear	Functional checks Instrument calibration
Relays	Insulation resistance	Insulation resistance Functional checks Visual inspection for evidence of electrical degradation Coil temperature Dissipation factor*
	Erratic operation	Function / response time checks Visual inspection for mechanical degradation

Data to establish the qualified life of sensors and the corresponding environmental conditions are needed to provide a basis for evaluating aging effects. Since temperature and moisture are the two most prominent stressors for sensors, it is particularly important to identify the conditions that were established during qualification testing. This information should be found in the EQ files for each item of equipment. Specified ambient temperature is also needed to evaluate remaining life of processing logic devices. This information can be found in the manufacturer's specification for the devices.

Sensors

The majority of RPS sensors are subject to the requirements of 10 CFR 50.49 [B7]. This document specifies the requirements for qualification of electrical equipment required to function in a postaccident environment. An aging assessment should consider these requirements.

IEEE Std 323-1983 describes seven methods of extending qualified life. The method used in this example examines the conservatism in the type test program for aging mechanisms and use the conservatism to recalculate qualified life.

The methodology developed for an aging assessment in part consists of identifying and documenting conservatism used to estimate the parameters from which the qualified life was originally calculated and then recalculating the qualified life.

In this example, it is assumed that the original qualification of the transmitters is 10 years in an ambient temperature of 48.9 °C (120 °F). The limiting component activation energy is the example of 0.78 eV. The actual installed service environment is 40.0 °C (104 °F). The Arrhenius model from EPRI NP-1558 [B12] is shown in Equation (D.1).

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$$t = B \exp [\phi/kT] \quad \text{(D.1)}$$

where

t is the time to reach a specified end-of-qualified-life condition or lifetime,

B is a constant [related to the amount of degradation that will have occurred at end of time t, or $B = g(t)/A$, where $g(t)$ is the amount of reactions occurring through time t],

ϕ is the activation energy (eV) for a chemical reaction of concern and indicative of aging susceptibility,

k is the Boltzmann's constant (0.817×10^{-4} eV/K),

T is the absolute temperature (K) of the service condition.

A lifetime at a different temperature can be calculated by solving Equation (D.2), using the two temperatures (T_1 = temperature used for the original qualification and T_2 = temperature of the actual installed service environment).

$$t_2/t_1 = \exp \{(\phi/k)[(1/T_2) - (1/T_1)]\} \quad \text{(D.2)}$$

According to Arrhenius model, the revised qualified life of the transmitter was assessed to be approximately 23 years. The residual life is the difference between the new assessed life (23 years) and the present age of the transmitter. The other aging effects from which the qualified life was originally calculated were reviewed and determined not to be limited by this extended life. Examples of other aging effects that were utilized to simulate end-of-life conditions include process cycling, calibration cycling, environmental cycling, and vibration.

There are limitations in the use of this method to establish revised qualified life as discussed in EPRI NP-1558 [B12]. The user should review historical records to assure that the environmental temperature has always been maintained within the new temperature. In addition, justification, such as establishing controls, should be provided for assuring that the temperature is maintained within the new value. The qualified life should be reevaluated when new or changed conditions have been observed.

The cost of providing this information should be considered with regard to the benefit of extending the life of that particular item of equipment.

Processing logic devices

If ambient air temperature is maintained at approximately 23.9 °C (75 °F), equipment is periodically cleaned, relay testing is periodically performed, and battery equalizing charge is limited to 140 V dc for 24 hours in a 30-day period, industry experience indicates that the normally energized and de-energized relays should achieve a life of 12–15 years. However, by trending the plant-specific data of ambient temperature and applied voltage, a more precise life expectancy may be predicted in a manner similar to that used previously for sensors. This would require obtaining relay temperatures (metal temperatures) and evaluating the temperature-sensitive materials (primarily insulation material). If this does not provide the residual life that is desired, or if obtaining actual operating temperatures is too costly, the availability of alternative relay suppliers and the impact of installing such relays should be evaluated.

Calibration data for sensors is useful to establish whether a particular sensor is experiencing conditions that lead to calibration drift. Test data showing response times of processing logic devices is useful for establishing that these devices are operating satisfactorily and to identify devices that require frequent attention. This data may be in maintenance records for each item of equipment showing "as-found" and "as-left" conditions.

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D.2 Emergency diesel generator

The nuclear station emergency diesel generator (EDG) is the primary source of standby Class 1E power for the plant. It is designed to provide reliable AC power during accident and abnormal operating conditions when the main turbine generator and off-site power sources are not available. As part of the Class 1E electrical system, the diesel engine and other largely mechanical components are within the scope of IEEE Std 387-1995 [B38]. IEEE Std 387-1995 [B38] clearly includes the engine, generator, air starting system, combustion air system, cooling water system, and similar supporting systems within the intended scope. Thus, this annex addresses heat exchangers and piping corrosion as an example of aging concerns that are not normal electric or electronic responsibilities.

At this point in the aging assessment process, it is appropriate to consider whether any of the emergency diesel generator systems have spare parts or other obsolescence problems. The instrument and control subsystem, including solid-state electronics, is of special concern. The technology in this area has been and is expected to continue to evolve at a fast rate. The earlier open relay technology is subject to repeated failure problems as determined by a review of this subsystem's maintenance history and it is included outside the scope of this aging assessment that replacement with more modern sealed relays is needed. An engineering study should evaluate any logic and control elements that are to be replaced to ensure that replacement components meet functional and safety criteria for this subsystem. The remainder of the EDG systems and components are to be the subject of an aging assessment.

D.2.1 Evaluation boundaries

The emergency diesel generator is really an integrated small power plant multisystem system whose components are several separate but dependent systems. The evaluation boundary is, therefore, established by the boundaries of the following systems:

a) Generator and exciter system
b) Engine structure and drive train
c) Fuel storage and delivery system
d) Engine cooling system
e) Engine lubricating system
f) Starting system
g) Intake system
h) Exhaust system
i) Instrument and control system (excluded from further consideration as described previously)

These systems could be divided into yet smaller modules such as sensors, cables, processing electronics, logic devices, and engine parts. However, it is found that no significant, definable benefit derives from further complicating the assessment analysis for this case example.

D.2.2 Identify safety function

The safety function of the emergency diesel generator is to be able to operate and supply electrical power at up to design electrical load whenever necessary during the life of the plant. Each system, as follows, also has its unique safety function:

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a) *Generator and exciter system.* Convert the mechanical rotational energy of the shaft to three-phase electrical energy.

b) *Engine structure and drive train.* Convert stored energy of the fuel oil through the combustion process to shaft rotational energy.

c) *Fuel storage and delivery system.* Store a short-term supply of fuel near the diesel engine and a longer term supply of fuel farther away and underground and transfer and provide fuel to the diesel engine as needed without loss of continuity for a specified length of time.

d) *Engine cooling system.* Cools and removes waste heat from the diesel engine in sufficient amounts to prevent overheating.

e) *Engine lubricating system.* Lubricates and cools sliding metal parts within the diesel engine to both reduce frictional losses and prevent excessive wear.

f) *Starting system.* Provides initial rotation of the crankshaft until sustained engine torque is achieved (because the diesel engine provides no starting torque with the shaft at rest).

g) *Intake system.* Provides intake air for the diesel engine combustion process at a rate consistent with electrical power demand.

h) *Exhaust system.* Removes exhaust air from the diesel engine at a rate consistent with electrical power demand. The function of noise dampening is considered nonessential.

D.2.3 Equipment location

The emergency diesel generators are located in their own dedicated building but in close proximity to the reactor, auxiliary, and control buildings.

D.2.4 Service conditions

The environment in the emergency diesel generator building is controlled by a safety-grade HVAC system. The temperature is typically maintained at or below 48.9°C (104°F). The humidity is typically maintained at or below 80%.

D.2.5 Materials of construction

The materials used in the construction of the emergency diesel generator systems are identified in the vendor manual and supportive documentation (and are inappropriate to list comprehensively in this guide).

D.2.6 Identify and assess aging effects

This step consists of an identification and assessment of aging effects that lead to a detrimental effect on system safety function. These aging effects are found from a review of major industry and plant-specific documents and databases. In general, a review of plant-specific history would be sufficient but in this case only 10 years of plant specific data is available and a decision was made to also consider industry-wide identified aging effects to be additionally comprehensive.

A review of an industrial database compilation (see NUREG/CR-5057 [B72]) from four sources identified 1984 emergency diesel generator failures over a 19-year period. Of these 1064 were judged to be related to aging and 274 of the 1064 were associated with the instrument and control system, which has been screened out from further consideration. Of the remaining 780 age-related failures, six major aging effects encompassing over 60% of the failures were noted and are summarized in Table D.2. The remaining aging effects were noted to be unique cases or otherwise not relevant to the subject plant and manufacturer type.

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Table D.2—Summary of EDG major aging effects from industry records

Aging effects	System	Cause and assessment comment
Degradation in or no fuel delivery to diesel engine	Fuel	Piping, injection pump, or injector failure from vibration and other adverse environment effects.
Reduced cranking speed during start-up	Starting	Air admittance valve or starting motor failure from adverse environmental conditions or initial design flaw.
Reduced or no cooling water flow	Cooling	Vibration-induced failure of heat exchanger internal baffles, piping, and pump.
Crankcase cracking or leakage	Engine structure and drive train	Vibration and improper operation.
Low engine compression	Engine structure and drive train	Cylinder liner failure from manufacturing defects, thermal stresses, and design problems.
Excessive bearing or piston ring wear	Lubricating	Oil contamination, poor maintenance, and design flaw.

Next plant-specific EDG records in the form of station equipment history, surveillance testing records, maintenance reports, LERs, and root cause evaluations are reviewed for aging concerns such as detrimental parametric trends, excessive maintenance or repairs, and multiple failures. Table D.3 summarizes the results of this review.

Table D.3—Summary of EDG major aging effects from plant-specific review

Aging effects or concern noted	System	Cause or comment
Increasing jacket water cooling temperature trend over 5-year period	Cooling	Fouling on service-water side of jacket cooling water system heat exchanger.
Excessive maintenance repairs on starting reciprocating air compressors	Starting	Vibration and normal wear. This is a nonsafety portion of the EDG.
Unexplained decrease in underground storage tank fuel oil level	Fuel	Excessive galvanic corrosion because of apparent inadequate cathodic protection.
Loosened brackets on fuel supply line where mounted to the diesel engine	Fuel	Vibration.
Reduced starting airflow rate	Starting	Corrosion blockage in one of the starting air isolation valves from apparent wrong choice of materials in valve construction. Valve was replaced.

D.2.7 Aging management

Subclause D.2.6 identified and assessed aging effects. This section develops aging management techniques to address these aging effects with consideration to existing programs at the plant and new approaches where

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none presently exist. IEEE Std 387-1995 [B38] includes additional information on monitoring and trending of emergency diesel generators.

In general, if proper maintenance practices are followed such as periodic lube-oil replacement and periodic testing with slower engine loading, the engine structure, drive train, and fuel delivery subsystems should have a long lifetime. The fuel oil tanks should be cleaned and tank wall measurements should be made by NDT methods to ensure that adequate wall thickness remains.

The design calculations for the underground fuel oil storage tank wall thickness and transfer piping thickness should be reviewed. The actual piping installed may greatly exceed the calculated wall thickness, so this piping may be found to be adequate for additional years of service life. The storage tanks, however, may not have enough design margin for 60 years, so an inspection and thickness measurements should be part of the aging assessment.

The generator insulation may be inspected. On the basis of light duty and mild environment it experiences, no signs of degradation should be found. By using the actual temperatures and the Arrhenius model calculation, the generator insulation residual life may be calculated and may be found acceptable for additional years of service life. The power cables could be analyzed using Arrhenius methodology and by considering actual plant data. Since temperature influences and chemical attack from fuel oil are the main aging degradation concerns, analysis by Arrhenius methodology and a visual inspection for chemical attack may be used to determine residual life.

For the starting system, the wall thickness of air delivery piping, storage tanks, and drain lines should be measured and evaluated. Wall thinning and deposits should not be detected. Some small sections of original carbon-steel pipe may be found with questionable wall thickness, and a decision to replace with stainless-steel pipe or new carbon-steel pipe may be made.

The cooling subsystem should be visually inspected and an NDT examination should be made of 10–25% of the heat exchanger surfaces for wall thinning. Excessive fouling should not be found on the tubing outside surfaces and the shell side of the heat exchanger. If fouling is found, it should be removed mechanically or chemically, without damage to the metal surfaces. The heat exchangers should be evaluated and determined to be serviceable for additional years of service life, on the basis of the absence of tube wall thinning below minimum design thickness plus any allowance for corrosion thickness.

NOTE—ANSI/ASME design, fabrication, and construction codes / standards should be referred to for assessment of mechanical tanks, piping, HVAC, and components.

Table D.4 summarizes the results of this subclause and other aging management recommendations.

D.3 Motor control centers

Motor control centers (MCCs) either provide power to other systems or provide control of system operation. IEEE Std 649-1991 [B51] provides additional information on MCC component aging effects.

D.3.1 Define evaluation boundaries

The subcomponents performing MCC functions generally include circuit breakers, starters, thermal overloads, transformers, fuses, and control relays. The control relays used depend on the particular application. The present industry trend is to replace these subcomponents at the end of their design or qualified life. Replacement is a very time-consuming and expensive process, even if the cost of the component may be relatively low, in view of the associated downtime and identical items being used in MCCs throughout the plant.

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Table D.4—EDG aging management summary

System	Identified aging effects	Monitoring approach	Conclusions
Generator and exciter	None identified	Existing maintenance program periodically monitors electrical windings for partial discharge.	Existing program is adequate.
Engine structure and drive train	Crankcase cracking or leakage	Existing maintenance program includes periodic inspection of crankcase for integrity failure concerns.	Existing program is adequate.
Fuel	Fuel injection rate degradation	Existing maintenance program includes periodic monitoring of fuel injection capacity for decrease.	Existing program is adequate.
Fuel	Loosened brackets on fuel supply line where mounted to engine	Prior failure and root cause evaluation resulted in change to surveillance procedure to check for looseness during periodic start-ups.	Existing program is adequate.
Fuel	Unexplained decrease in underground fuel oil storage tank level	Monitor fuel oil storage tank wall thickness via NDT. Also consider baseline inspection of the underground transfer piping.	New recommendation.
Cooling	Reduced or no cooling water flow and increased jacket water temperature trend	Surveillance program includes trending of jacket water temperatures with a threshold for action to clean heat exchanger.	Existing program is adequate.
Lubricating	Piston ring / bearing wear or failure	Existing surveillance program includes monitoring and trending of lube oil temperature and oil contaminant and wear product concentrations with thresholds for action.	Existing program is adequate.
Starting	Reduced cranking speed during diesel start / reduced starting airflow rate	One-time past plant material incompatibility problem was fixed by valve model replacement. Future corrosion problems may be detected by trending a baseline-adjusted correlation of cranking speed to starting air pressure.	New recommendation.
Starting	Excessive maintenance on air compressors	These air compressors are not safety-related and not critical to EDG operation. Multiple air compressors assure availability for maintaining the safety-related starting air receivers at the required pressure level.	No recommendation necessary.

D.3.2 Identify safety functions

MCCs are low-voltage (less than 600 V) controllers that start and stop, provide continuous power to, and protect motors that drive pumps and motor-operated valves. Typically, a motor controller unit consists of a molded-case circuit breaker, a magnetic contactor, a transformer, relays, and thermal overload devices. Age-related degradation of these subcomponents has impacted safety system availability and operation.

D.3.3 Identify plant locations

The MCCs being evaluated are located in the auxiliary building.

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D.3.4 Identify service conditions

MCCs are located in environments ranging from the benign (i.e., atmospheric effect only) to the harsh environment resulting from an accident (i.e., high temperature and high humidity). The ambient temperature ranges from –28.9 °C (–20 °F) to 73.9°C (165 °F) depending on the location of the equipment within the plant. Plants in coastal areas are subject to air with high humidity and salt content that can cause surface corrosion or pitting.

D.3.5 Identify materials of construction

The MCC consists of structural components; i.e., heavy-gauge steel and aluminum / copper bus bars, mechanical components such as handle mechanisms, insulated stab blocks, bus support insulators and barriers, and electrical components such as terminal blocks, breakers, disconnects, switches, transformers, push buttons, indicating lights, and cables.

The following types of components can be deleted from future aging assessment:

a) Those not subject to any significant aging (such as structural components and other metallic parts)

b) Those components replaced as part of normal maintenance (such as indicating lights and thermal overload heaters)

As a result, the following components are identified for further aging assessment:

— Circuit breakers / fuses

— Relays

— Transformers

— Terminal blocks

— Starters / contactors

— Push buttons and auxiliary switches

— Bus and stab block insulators and barriers

D.3.6 Identify aging effects

An important concern is the impact of equipment aging on the capability of plant safety systems to mitigate the consequences of accidents and abnormal transients. The effects of such degradation on the ability of the plant to achieve safe shutdown during an accident should include an evaluation of stresses that are imposed during the accident on the equipment, as well as the potential for the age-related failure degradation to conditions mentioned previously. Various failure modes, causes, and aging effects are summarized in Table D.5 for each of the MCC components.

D.3.7 Aging management

There are observable parameters of MCC performance for each of the components that have potential to predict failure of equipment due to aging. Some of these parameters are mentioned in the following subclauses, and include both quantitative and qualitative type of information. Some may require that the MCC be shut down before evaluation. Table D.6 provides a list of the most common observable parameters for the limiting age-related critical characteristics for MCC components.

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Table D.5—Summary of typical failure modes, causes, and effects

Component	Failure mode	Failure cause	Aging effects
Circuit breaker	Fail to open Fail to close	Mechanical stresses	Cycle fatigue, e.g., cycling due to downstream system failure
			Wear during normal operation
			Binding due to linkage distortion, bearing malfunction, etc.
		Foreign material / sticking	Buildup of grease or other foreign substances on contacts
		Surface deterioration	Pitting and corrosion of contact surface (arcing)
		Defective spring	Material deterioration
		Insufficient closing torque	Degraded internal components
	Inadvertent trip	Out of adjustment	Normal protective action of MCC tripped on load from downstream system
		Defective latch ground / short	Wear-out
			Degraded contact resistance
			Improper maintenance insulation deterioration
		Misalignment	Normal wear of internals
	Fail to trip	Mechanical stresses	Wear-out of internals during operation
		Surface degradation	Pitting and corrosion of contact surfaces
		Foreign material	Buildup of grease or other foreign substances on contacts
	Out of calibration	Setpoint drift	Deterioration during normal operation
			Corrosion of contact surface (arcing)

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Table D.5—Summary of typical failure modes, causes, and effects (continued)

Component	Failure mode	Failure cause	Aging effects
Relay	Open circuit	Overheating	Deterioration and breakdown of coil electrical insulation due to usage
		Contact surface degradation	Pitting and corrosion of contact surfaces
	Fail to open Fail to close	Foreign material accumulation of dirt and grease on contact surfaces malfunction, etc.	Binding and lack of circuit continuity
		Surface degradation	Pitting and corrosion of contact surfaces
		Misalignment	Excessive vibration and wear during operation
		Mechanical stresses	Normal wear and distortion of linkage
	Response on incorrect signal	Out of calibration	Setpoint drift due to wear during normal operation
Transformer	Open circuit	Overheating	Burned-out primary or secondary coils due to excessive loads
	Short / ground	Overheating	Deterioration and breakdown of electrical insulation
Terminal block	Poor connection open circuit	Mechanical stresses	Vibration and wear resulting from normal operation
	Ground / short	Environmental effects (humidity, dust, etc.)	Conduction path due to excessive temperature
Starter / contactor	Fail to close	Mechanical stresses	Fatigue due to excessive cycling of subcomponents
		Surface degradation	Pitting and corrosion of contact surfaces
		Impeded armature	Non-uniform magnetic driving force
		Foreign substance	Buildup of dirt and grease during operation
	Fail to open	Overheated	Burned out due to excessive cycling and normal usage degradation

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Table D.5—Summary of typical failure modes, causes, and effects (continued)

Component	Failure mode	Failure cause	Aging effects
Thermal overload relay	Open circuit	Overheated	Excessive ambient conditions
			Cyclic fatigue
			Normal protective function
	Would not operate	Surface degradation	Pitting and corrosion of relay surfaces
	Trip and response on incorrect signal	Out of calibration	Setpoint drift due to wear during operation
			Error in manufacturing of subcomponents
		Sticking	Buildup of foreign material
Coil part of contactor or relay	Open circuit	Overcurrent condition	Burned out from normal and extreme operation
	Short / ground	Material degradation	Insulation breakdown

D.3.7.1 Testing

Several tests are useful for aging management in assessing the performance characteristics of the MCC, such as

a) Continuity test following repair or replacement of a component.

b) Contactor mechanical and electrical checks, including verification of pickup and dropout voltages.

c) Verification of circuit breaker trip setpoint. Compare timing with manufacturer's data.

d) Testing of time-delay relays where applicable.

e) A final energized operational test of each control device.

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Table D.6—Observable parameters for limited age-related critical characteristics

Stressors	Aging mechanisms	Observable parameters
Moisture-contaminated atmosphere	Surface degradation Corrosion, pitting Arcing	Contact-resistance and meggering
Temperature	Overheating	Meggering
Humidity Contaminants	Deterioration of insulation Loss of electrical continuity Sticking, binding	Phase-to-ground resistance and meggering Physical inspection
Overcurrent demand	Degradation of material integrity	Electrical insulation
Vibration	Loosening of connection Electrical short / ground	Connection tightness
Radiation	Organic material embrittlement	Electrical insulation Mechanical strength
Incorrect adjustment	Material wear Inadequate maintenance and procedures	Free motion of internal parts Condition of mechanical linkage Reduction in spring compression / spring fatigue tension forces

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D.3.7.2 Periodic maintenance

On the basis of input received from manufacturers and utilities, several maintenance actions are recommended that can be useful for MCC aging management.

MCC component	Maintenance action
Structure	Check for moisture, oil, and foreign material. Vacuum clean.
Bus bar	Examine for pitting, corrosion, and overheating. Check connections for tightness.
Circuit breaker	Test and examine for proper operation.
Operating mechanism	Exercise ON, OFF, RESET buttons; verify interlocks.
Fuses	Check for arcing or overheating.
Starter	Inspect contacts and replace if pitted or corroded.
Overload heater	Manually trip the device and inspect for proper operation. Check size of heater.
Metering	Calibrate important indicators.
All components	Inspect connections for tightness; inspect wiring for signs of wear and overheating.

D.4 Insulated cables

An insulated electric cable is an assembly of a metallic conductor or conductors, insulation, and any other surrounding structural material, spacers and jacket. Cables are grouped according to voltage rating into three categories for the purposes of this assessment: i.e., low-voltage (less than 2 kV), medium-voltage (2–15 kV), high voltage (greater than 15 kV).

An aging assessment of insulated electric cables is performed as a basis for a nuclear station's license renewal application. This assessment involves the evaluation of insulated cables for operation up to 60 years. License renewal includes EQ insulated cables, other safety-related cables, some non-safety-related cables, and cables required for specific regulated events (such as station blackout, fire protection, pressurized thermal shock, and anticipated transient without a scram). Cables currently included in the plant EQ program are adequately managed by that program and are not included in this aging assessment. A reference for this type of approach can be found in SAND96-0344 [B74].

D.4.1 Define the evaluation boundaries

The evaluation boundary is the outermost surface of the cable assembly. This assessment evaluation would, therefore, include the jacket, insulation materials, metallic conductors and all other materials used in the construction of different parts of cables such as the cable shielding, cable fillers, and cable armor. To simplify the scope of this example assessment, cable connections are not included.

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D.4.2 Identify safety functions

Insulated electric cable has two functions: (1) to connect two elements in an electric circuit for transmission of current or signals and (2) to insulate the conductor(s) from other conductors, grounds, and surrounding support structural.

D.4.3 Identify plant locations where the cables are installed

Cables are found in most areas of the plant and are exposed to numerous and various plant environments. Except for direct-buried cables, cables are installed in, attached to, or otherwise supported by a structure (e.g., conduit, cable trench, cable tray in a building). Identifying the structures and areas containing cables to be assessed allows identification of a bounding set of insulated cables and conditions (as opposed to evaluating each cable individually).

Table D.7 defines the scope of locations for this aging assessment. This table was derived from the list of structures within the scope of license renewal and the single location area containing direct-buried cable.

Table D.7—Structures and areas included in the cable assessment evaluation

Structure or area	Description
Auxiliary buildings	Includes all levels of the auxiliary buildings including the hot machine shop and spent fuel pools and penetration rooms
Intake structure	Includes the condenser circulating water (CCW) pump intake structure
Reactor buildings	Includes all levels of the reactor buildings and the unit vents
Standby shutdown facility	Includes all levels and rooms in the standby shutdown facility
Turbine buildings	Includes all levels of the turbine buildings and the switchgear blockhouses
Yard structures	Includes all areas and components outside the other buildings. Specifically, the 230 kV switchyard structures and relay house (includes the area within the switchyard boundary fence), transformer yard (components associated with the start-up transformers), cable trenches, cable conduit, direct-buried cable

D.4.4 Identify the cable service conditions

The aging assessment needs to consider two types of service condition stressors: environmental and operational. These two types are discussed in D.4.4.1 and D.4.4.2.

D.4.4.1 Environmental conditions

Thermal, radiation, and moisture service conditions are determined as described in D.4.4.1.1, D.4.4.1.2, and D.4.4.1.3, and the results are summarized in D.4.4.1.4.

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D.4.4.1.1 Temperature conditions

Temperature data values were extracted from various design documents. For areas where no design data could be found, conservative bounding temperature values were assigned and used on the basis of engineering judgment through consideration of adjoining locations and comparison of heat sources and heat sinks.

Table D.8 summarizes the design temperature values identified. These temperature values are considered upper-limit reasonably bounding temperatures because they do not account for lower daily variations (day vs. night) and seasonal variations (summer vs. fall, spring, or winter), as well as plant historical capacity factor effects.

Table D.8—Plant bounding temperature conditions

Structure or area	Specific area description and comments	Bounding temperature
Auxiliary buildings	Areas cooled by the auxiliary building ventilation system	40.0 °C (104 °F)
	Spent fuel pool areas	40.0 °C (104 °F)
	Equipment rooms (designed for 86 °F)	32.2 °C (90 °F)
	Control rooms, cable rooms (designed for 74 °F)	29.4 °C (85 °F)
	Control battery rooms	26.7 °C (80 °F)
	Areas cooled by the auxiliary building air conditioning system	23.9 °C (75 °F)
Intake structure	Areas exposed to site ambient	40.6 °C (105 °F)
Reactor buildings	High elevations in steam generator cavities	55.6 °C (132 °F)
	Elevation around top of reactor coolant pumps	52.2 °C (126 °F)
	Elevation around bottom of reactor coolant pumps	46.7 °C (116 °F)
Standby shutdown facility	Diesel generator, switchgear, pump, HVAC equipment rooms	40.0 °C (104 °F)
	Control, computer, battery, response (CAS) rooms	22.2 °C (72 °F)
Turbine buildings	General areas	40.6 °C (105 °F)
Yard structures	Areas exposed to site ambient	40.6 °C (105 °F)
	Cable trenches, direct-buried, buried conduit	26.7 °C (80 °F)

D.4.4.1.2 Radiation conditions

Radiation dose service conditions for normal operation were obtained from the station's environmental qualification program specifications. The values given are conservative maximums and the actual 40-year dose is normally lower (in some cases, much lower). The projected normal dose for 60 years is determined by multiplying the current 40-year normal dose by 1.5 (i.e., 60 ÷ 40). Radiation doses less than 1×10^3 rad (10 Gy/h) are considered negligible.

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Table D.9 summarizes the radiation dose values identified for each structure and area within the assessment scope.

Table D.9—Plant radiation dose data

Structure or area	Maximum 40-year normal operating dose (rads)	Maximum 60-year normal operating dose (rads)
Reactor buildings	3×10^7	4.5×10^7
Auxiliary buildings	1×10^6	1.5×10^6
Turbine buildings Intake structure Standby shutdown facility Yard structures	Negligible	Negligible

D.4.4.1.3 Moisture conditions

Moisture conditions were determined from observations made during plant walkdowns. Although many areas could be subjected to low amounts of humidity or a one-time pipe leak, of concern for long-term aging are areas where components are subjected to wetting. Wetting refers to a significant amount of moisture in contact with cable, such as would be produced by repeated instances of standing water, system leakage / spray, flooding, and outside areas exposed to precipitation. Areas subject to wetting were noted during the plant walkdowns. Table D.10 summarizes the areas where moisture was found and gives a clarifying description.

Table D.10—Plant moisture data

Structure or area	Moisture found	Description
Auxiliary buildings	No	No areas subject to moisture.
Intake structure	Yes	Outside areas exposed to precipitation.
Reactor buildings	No	No areas subject to moisture.
Standby shutdown facility	No	No areas subject to moisture.
Turbine buildings	No	No areas subject to moisture since the turbine building for this plant is covered. Some plants do not have enclosed turbine buildings.
Yard structures	Yes	— Outside areas exposed to precipitation. — Cable trench floors subject to standing water. — Direct-buried cables subject to surface water drainage and soil moisture. — Buried conduit and manholes may be subject to water collection.

NOTE—Cable jacket materials have no significant effect on the normal aging process of the primary cable insulation except when subject to moisture effects.

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D.4.4.1.4 Summary of environmental service conditions

Cables included in this assessment are installed in the locations identified in Table D.11. Bounding environmental conditions for these locations have been determined (see Table D.8, Table D.9, and Table D.10) and have been combined in Table D.11 for easy reference.

D.4.4.2 Operational conditions

The only operational condition stressor applicable to cables within the evaluation boundary is self-heating temperature rise. For purposes of evaluating the effect of this stressor, cables are considered to be within one of two application categories: power or instrument and controls (I&C). Self-heating temperature rise applies only to the first (power applications) category as explained in the following list:

a) *Power applications*. Cables used to supply power to devices or components where the cables carry a large amount of current, relative to their rating, for significant periods of time and, therefore, may be subject to self-heating temperature rise from the current they carry.
b) *I&C applications*. Cables used to supply power to devices or components where the cables carry a small amount of current, relative to their rating, or carry current for short periods of time and, therefore, are not subject to significant self-heating temperature rise from the current they carry.

Power system load values used for performing load and voltage analysis are found in the calculation for the corresponding power system. The calculation contains information for each load (e.g., bus, compartment, voltage, load and load factors) connected to the power system bus. The required information was converted into a spreadsheet format and the loads were matched with the power system one-line diagrams to identify the number of conductors and the conductor size for each load.

The conductor ampacity values were calculated starting with values in an IEEE S-135/IPCEA P-46-426 table designated for cables with three concentric strand copper conductors, 90 °C rated rubber insulation, in 40.0 °C (104 °F) ambient air. This IPCEA table gives values for cable at 1 kV, 8 kV, and 15 kV. The design criteria at this plant specified that for cables rated 2–5 kV, ampacities are determined by starting with the value in the 1 kV column and multiplying this by a derating factor. For cables rated 8–15 kV, ampacities are determined by starting with the value in the 15 kV column and multiplying this by a derating factor.

Ampacity values for 600 kcmil conductors (not shown in the IPCEA table) are calculated by interpolating between the 500 kcmil and 750 kcmil values. Ampacity values for #10 AWG and #12 AWG (also not shown in the IPCEA table) are taken from Table 310-16 of the National Electrical Code® (NEC®) [B63] for 90 °C rated copper conductors.

The ampacity values are then derated with a multiplying factor (0.82) for single-layer horizontal placement in ladder tray with maintained spacing given in IEEE S-135/IPCEA P-46-426 Table VII, which matches the plant design. The #10 AWG and #12 AWG values in the NEC table are given for a 30.0 °C (86 °F) ambient, so these cables are derated by an additional correction factor (0.91) for use in a 40.0 °C (104 °F) ambient. This results in a 0.7462 multiplying factor (0.82×0.91) for these size conductors.

Use of the IPCEA and NEC tables described previously, and the use of these derating factors is specified in the design criteria of this plant. Table D.12 shows the conductor sizes, initial ratings, derating factors, and resulting conductor ampacity values.

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Table D.11—Cable environment conditions

Stressor	Structure or area	Insulation material or specific area	Bounding value
Temperature	Reactor buildings [safe shut-down facility (SSF) cables]	EPR, FR-EPR, Kapton, FR-XLPE [see Note]	55.6 °C (132 °F)
	Auxiliary buildings Intake structure Standby shutdown facility Turbine buildings Yard structures	All insulation materials	40.6 °C (105 °F)
	Cable trenches, buried conduit, direct-buried, outside ambient	PVC (overall jacket)	26.7°C (80 °F)
Radiation	Reactor buildings [SSF cables]	EPR, FR-EPR, Kapton, FR-XLPE [see Note]	4.5×10^7 rad (4.5×10^5 Gy)
	Auxiliary buildings	All insulation materials	1.5×10^6 rad (1.5×10^4 Gy)
	Turbine buildings Intake structure Standby shutdown facility Yard structures	All insulation materials	Negligible
Moisture	Intake structure	Outside areas exposed to precipitation	Precipitation
	Yard structures	Outside areas exposed to precipitation	Precipitation
		Cable trench	Trench floor standing water
		Direct-buried cable	Surface water drainage and soil moisture
		Buried conduit	Water collection

NOTE—This assessment does not include cables in the station's EQ program. Most cables within license renewal scope installed in the reactor buildings are included in the EQ program. In order to define the scope of cables to be assessed here, the scope of the EQ program was compared to the license renewal scoping criteria to determine those cables not already addressed by the EQ program. This comparison revealed that except for some station blackout (SBO) cables fed from the standby shutdown facility (SSF), all license renewal cables installed in the reactor buildings are included and addressed in the EQ program. These SSF cables have EPR, FR-EPR, Kapton, or FR-XLPE insulation and only these insulation materials need be assessed for the reactor building environments.

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Table D.12—Conductor ampacity values and derating factors

Conductor size (AWG or kcmil)	IPCEA table cable ampacity	Ampacity derating factor	Conductor ampacity
12	30	0.7462	22.4
10	40	0.7462	29.8
8	59	0.82	48.4
6	79	0.82	64.8
4	104	0.82	85.3
2	138	0.82	113.2
1	161	0.82	132.0
1/0	186	0.82	152.5
2/0	215	0.82	176.3
3/0	249	0.82	204.2
4/0	287	0.82	235.3
250	320	0.82	262.4
350	394	0.82	323.1
500	487	0.82	399.3
600	538	0.82	441.2
600 (15 kV insulation)	589	0.82	483.0

These current ratings were entered into the spreadsheet and the combined data used to calculate the self-heating temperature rise that occurs when each conductor carries its normal connected load. The calculated temperature rises were sorted in descending order.

NOTE—At this point in the determination of self-heating temperature service conditions, it is necessary to obtain insulation materials information from the approach described in D.4.5. For most equipment types, normal service conditions would be typically defined first and then the limiting service conditions would be used to limit the amount of material research information required. However, for power application cables and their attendant self-heating effects, it is more expeditious to identify and use cable application insulation materials information in conjunction with ampacity-derived temperature rise values to define limiting combinations for further assessment.

For simplification purposes, two distinct bounding temperature rise approaches were used for power cables as described in the following paragraphs.

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The decreasing temperature rise sorting provided by the spreadsheet produced 30 distinct self-heating temperature rise values above 10 °C. By comparing the conductor size and voltage on the spreadsheet list to the power cable applications and conductor sizes identified in Table D.15, possible insulation types are identified for each distinct value in the list. For example, 4 kV and 7 kV applications use only EP, EPR, EPDM, or FR-EPR insulated cables; 600 kcmil conductors are found only in EP, EPR, EPDM, or FR-EPR insulated cables; PE insulated cables are used at a maximum of 208 V applications. Possible cable insulation types were identified for each of the temperature rise values.

The highest calculated self-heating rise is used as the bounding value for insulation types with temperature rise values equal to and above 10 °C. For self-heating temperature rises of less than 10 °C, a bounding self-heating temperature rise of 10 °C is conservatively assigned (see Table D.16).

Self-heating temperature rise is not significant for cable insulation materials used only in I&C applications and, therefore, is not considered.

NOTE—The normal relationship between degrees Celsius and degrees Fahrenheit does not apply when reporting temperature rise as the "32" cancels out of the equation. Therefore, only degrees Celsius is reported when discussing temperature rise.

Table D.13 shows the results of the spreadsheet calculations and comparison reviews. As discussed earlier in D.4.4.1.4, the only reactor building cables being assessed are the SSF cables, which are not included in the EQ program. The SSF cables are found to be insulated with EPR, FR-EPR, Kapton, or FR-XLPE. The highest calculated SSF cable self-heating temperature rise is 12°C and is shown separately in Table D.13. Cables in cable trenches, buried conduit, direct-buried cable, and outside ambient are found to all have an overall jacket of PVC. The highest calculated self-heating temperature rise for these cables is 15 °C, as shown separately in Table D.13.

Table D.13—Cable self-heating temperature rise

Insulation material	Bounding self-heating temperature rise
EP, EPR, EPDM, FR-EPR	30 °C
PVC (overall jacket) (Cable trenches, buried conduit, direct-buried cable, outside ambient)	15 °C
EPR, FR-EPR, Kapton, FR-XLPE (RB SSF cables)	12 °C
Butyl, Hypalon, Kapton, PE, SR XLP, XLPE, FR-XLPE	10 °C
Fiberglass, polyalkene, PVC	Not significant

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D.4.4.3 Results—service conditions

Table D.14 summarizes service conditions from the previous three clauses for easier future reference by combining the environmental condition data with the operational conditions data.

Table D.14—Cable service conditions

Stressor	Structure or area	Insulation material or specific area	Bounding value
Temperature	Auxiliary buildings Intake structure Standby shutdown facility	EP, EPR, EPDM, FR-EPR	70.6 °C (159 °F)
		Butyl, Hypalon, Kapton, PE, SR, XLP, XLPE, FR-XLPE	50.6 °C (123 °F)
	Turbine buildings Yard structures	Fiberglass, polyalkene, PVC	40.6 °C (105 °F)
	Reactor buildings (SSF cables)	EPR, FR-EPR, Kapton, FR-XLPE	67.8 °C (154 °F)
	Cable trenches, buried conduit, direct-buried, outside ambient	PVC (overall jacket)	41.7 °C (107 °F)
Radiation	Reactor buildings (SSF cables)	EPR, FR-EPR, Kapton, FR-XLPE	4.5×10^7 rad (4.5×10^5 Gy)
	Auxiliary buildings	All insulation materials	1.5×10^6 rad (1.5×10^4 Gy)
	Turbine buildings Intake structure Standby shutdown facility Yard structures	All insulation materials	Negligible
Moisture	Intake structure	Outside areas exposed to precipitation	Precipitation
	Yard structures	Outside areas exposed to precipitation	Precipitation
		Cable trench	Standing water on trench floor
		Direct-buried	Surface water drainage and soil moisture
		Buried conduit	Water collection

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D.4.5 Identify the cable materials of construction

The insulation materials used in the construction of cables in the plant are identified from cable tabulation sheets that outline cable types, cable characteristics, and cable applications. The cable application information is used to identify if a cable type is used in power applications or I&C applications, because this information is used in D.4.4.2 to appropriately apply self-heating temperature rise. A summary of the station's cable tabulation sheet data is given in Table D.15, which is further summarized in Table D.16.

Figure D.1 shows a cross section of a typical power cable.

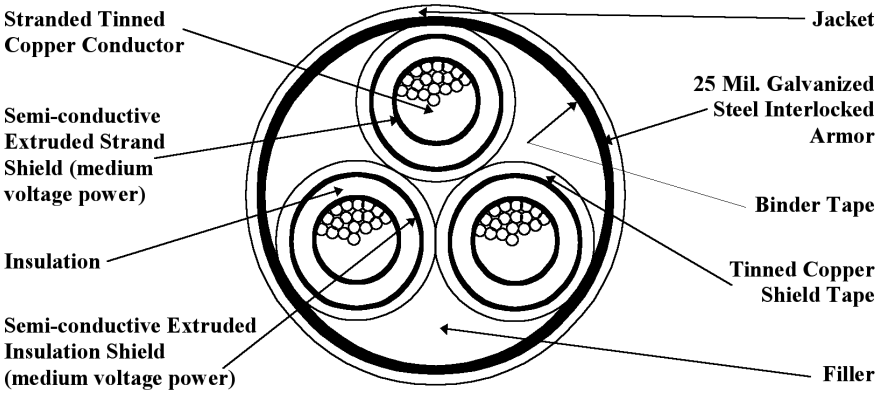


Figure D.1—Cross section of a typical power cable

D.4.6 Aging effect assessment

SAND96-0344 [B74] provides a comprehensive compilation and evaluation of information on the topic of aging and aging management for cables. It also evaluates the stressors acting on cable and connection components, industry data on aging and failure of these components, and the maintenance activities performed on cable systems. Included in the evaluation were the main subsystems within cables such as conductors, insulation, shielding, tape wraps, jacketing, and drain wires. The principal aging mechanisms and anticipated effects resulting from environmental and operating stresses on these systems were identified, evaluated, and correlated with plant experience to determine whether the predicted effects are consistent with field experience. Installation stressors were also examined. Therefore, the information, evaluations, and conclusions contained in SAND96-0344 [B74] are used as the starting point for the evaluation of aging effects in this example assessment. Background information pertaining to items covered in this section is discussed in more detail in SAND96-0344 [B74] or other industry sources.

The most significant and observed aging mechanisms for cables are listed in Table 4-18 of SAND96-0344 [B74]. The aging mechanisms from this table are used in this clause as the starting point for identifying aging effects for cables with adaptations made for a license renewal evaluation. The resulting potential aging effects along with the applicable stressors that are evaluated for cables are presented in Table D.17 and discussed in D.4.6.1, D.4.6.2, and D.4.6.3.

D.4.6.1 Medium-voltage cable insulation—moisture and voltage stress

Section 3.7.4 of SAND96-0344 [B74] describes a survey of 25 fossil and nuclear power plants that was conducted to determine the number and types of medium-voltage cable failures that have occurred. The survey identified only 27 failures in almost 1000 plant years of experience. The bulk of the failures that did occur were more related to wetting in conjunction with manufacturing defects, or damaged terminations due to improper installation.

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Table D.15—Cable materials included in the evaluation

Materials		Applications and power application cable sizes
Insulation	**Cable jacket**	
Butyl	PVC	**Power application:** 600 V power; 350 kcmil
EP, EPR, EPDM, FR-EPR	CPE, FR-XLPE, neoprene, PVC	**Instrument and control (I&C) application:** 600 V control, Bailey system interconnection cable, control, festooned cable for radiation monitoring on the bridge, festooned computer cable to fuel handling bridge, instrument and control cable, thermocouple extension cable; **Power application:** 600 V power, 4 kV power, 7 kV power, 15 kV power, discharge to tailrace valve #1/13/77, lighting; #12 AWG, #10 AWG, #6 AWG, #4 AWG, #2 AWG, #1 AWG, #2/0 AWG, #3/0 AWG, #4/0 AWG, 250 kcmil, 350 kcmil, 500 kcmil, 600 kcmil
Fiberglass	PVC	**I&C application:** Thermocouple (incore instrumentation)
Hypalon	Hypalon, neoprene	**I&C application:** Festooned cable for control interlocking on the bridge, instrumentation cable (RB), rod control, thermocouple cable (RB); **Power application:** Festooned Cable for Power to Bridge, Rod Control; #8 AWG, #6 AWG, #5 AWG, #4 AWG
Kapton		**Power application:** Pressurizer heater cable; #6 AWG
PE	PE, PVC	**I&C application:** 52 Ω carrier and transfer trip, communication cable, incore instrumentation, nuclear instrumentation, RCP vibration monitor, source range pre-amp low-voltage cable, telephone cable, trash rack vibration monitor, TV camera cable, video pair for carrier relays; **Power application:** 120 V and 208 V lighting and transformer secondaries, lighting; #12 AWG, #10 AWG, #2 AWG, #2/0 AWG, 250 kcmil
Polyalkene	PVF	**I&C application:** General-purpose hookup
PVC	Hypalon, PVC	**I&C application:** Annunciator prefabricated cable, Bailey system interconnecting cable, computer (special), computer cable (switchyard to control room), control rod drive cabinet to unit control board, GE-supplied EHC cable 60 ft long, ICS simulator cable, instrumentation cable, incore instrumentation, intrasite telephone system, PA system, process radiation monitoring cable, staging voice paging system, thermocouple cable, TV camera cable belden
SR		**I&C application:** Control rod drive; **Power application:** 600 V power, control rod drive rod control; #8 AWG, #4 AWG, #3/0 AWG, 300, 500 kcmil
XLP, XLPE, FR-XLPE	CPE, FR-XLPE, Neoprene, PVC	**I&C application:** 600 V control, alarms and signals, Bailey system interconnection cable, containment instrumentation, control (switchyard to control room), instrument cable, instrumentation cable (RB), miscellaneous instrumentation not to be used in RB, radiation monitor cable, switchboard hookup wire, thermocouple cable (RB); **Power application:** 120 V and 208 V lighting, lighting and power panelboard, transformer secondaries and associated equipment, lighting; #12 AWG, #10 AWG, #6 AWG, #2 AWG, #2/0 AWG, 500 kcmil

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Table D.16—Summary—cable material reviewed

Insulation material	Cable application	
	Instrument and control application	Power application
Butyl		X
EP, EPR, EPDM, FR-EPR	X	X
Fiberglass	X	
Hypalon	X	X
Kapton		X
PE	X	X
Polyalkene	X	
PVC	X	
SR	X	X
XLP, XLPE, FR-XLPE	X	X

Table D.17—Potential aging effects[a]

Voltage category	Component	Applicable stressor	Potential aging effects
Medium voltage	Cable insulation	Moisture and voltage stress	Electrical failure (breakdown of insulation)
Low voltage and medium voltage	Cable insulation	Radiation, oxygen	Reduced insulation resistance; electrical failure
		Heat, oxygen	Reduced insulation resistance; electrical failure

[a]Adapted from SAND96-0344 [B74].

The effects of moisture-produced water trees on medium-voltage cable were further examined in Section 4.1.2.5 of SAND96-0344 [B74]. Water treeing is a degradation and long-term failure phenomenon that has been documented for medium-voltage electrical cable with certain insulations such as XLPE or high molecular weight polyethylene (HMWPE). Water trees occur when the insulating materials are exposed to long-term, continuous electrical stress and moisture; these trees eventually result in breakdown of the dielectric and ultimate failure. The growth and propagation of water trees is somewhat unpredictable and few occurrences have been noted for cables operated below 15 kV. Since the formation and growth of trees varies directly with operating voltage, treeing is much less likely in 4 kV cables than those operated at 13 kV or higher.

Structures and areas where cable may be exposed to moisture are indicated in Table D.10. The in-scope medium-voltage cables in these areas are listed in Table D.18 and then discussed.

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Table D.18—Potential moisture exposure of medium-voltage cables

Potential moisture exposure area	Description	Nominal operating voltage
Cable trench	Condenser circulating water (CCW) pump cables	4160 V
	Standby shutdown facility (SSF) switchgear OTS1 power cables	4160 V
	230 kV and 525 kV switchyard power cables	4160 V
Outside ambient	CCW pump cables	4160 V
Direct buried	Transformer CT4 power cables	13.8 kV
	Transformer CX power cables	4160 V
Buried conduit	Auxiliary service water (ASW) switchgear cables	4160 V
	High-pressure service water (HPSW) pump A and B cables	4160 V

Cable trenches

Cable trenches are subject to moisture from precipitation that can seep around edges of the trench covers and down the trench sides, and may collect for a time in the trench floor if drainage is not adequate. The CCW cable trenches at this plant have floor drainage pipes to drain water. The cable trenches from the turbine buildings to the 230 kV switchyard and the trenches in the 230 kV and 525 kV switchyards at this plant have concrete sides with a sand and gravel bottom for water drainage. The cable trench from the SSF at this plant is built with a drain to prevent flooding. In addition, power cables at this plant are mounted to the trench sides and kept off the trench floor. These cables are constructed with interlocked armor and an overall PVC jacket. The extent of the moisture exposure for these cables is partial wetting if water runs down the side of the cable trench.

Outside ambient exposure

The CCW cables at this plant are exposed to precipitation where they exit the top of the intake structure to connect to the CCW pump motors. Historically (per the Updated Final Safety Analysis Report [UFSAR] of this plant), precipitation occurs less than 10% of the year. These plant cables are constructed with interlocked armor and an overall PVC jacket. The extent of the moisture exposure for these cables is wetting from precipitation.

Direct buried

The transformer CT4 power cables and the transformer CX power cables at this plant are direct buried in a trench and are exposed to moisture in the surrounding trench material. The trench for these cables is constructed such that the cables are surrounded with layers of sand. The cables are single conductor with EPR primary insulation, covered by bronze armor shield tape and an overall PVC jacket. The CT4 cables carry power only 4 hours per outage and are energized without load less than 12% of the time, which minimizes the voltage stress put on the cable insulation, which is the driving force behind moisture-related aging effects. The extent of the moisture exposure for these cables is wetting as precipitation water seeps from the surface and flows through the ground and the trench. The sand surrounding the cables aids rapid water drainage from the trench.

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Buried conduit

Buried conduit is subject to moisture intrusion from improperly sealed entrances (in areas subject to running water or water collection) and leakage through a conduit fitting or degraded conduit wall. The HPSW pump and ASW switchgear cables at this plant are single conductor with EPR primary insulation, covered with a copper shield, galvanized steel armor, and an overall PVC jacket.

Moisture in contact with the outer jacket does not present a moisture concern for these power cables at this plant. The overall PVC jacket is designed for direct buried and, unless the cable is improperly installed or otherwise damaged during installation, the overall PVC cable jacket precludes moisture from contacting the primary cable insulation. Therefore, aging effects related to moisture and voltage stress are not applicable for these cables at this plant.

D.4.6.2 Low-voltage and medium-voltage cable insulation—radiation, oxygen

The lowest threshold and the moderate-damage gamma radiation dose for the materials listed in Table D.16 were obtained from Table 4-7 of SAND96-0344 [B74] and Appendix C of EPRI NP-1558 [B12]. The threshold value is the amount of radiation that causes incipient to mild damage. Once this threshold is exceeded, damage to the insulation increases from mild, to moderate, to severe as the total dose increases by 1 to 2 orders of magnitude (an increase of 1 million rads to 10 million rads). The moderate damage value indicates the value at which the material has been damaged but is still functional. Additional information regarding specific insulation types is given in the right side column of Table D.19.

Comparing the radiation values given in Table D.19, with the service conditions shown in Table D.14, indicates that all of the insulation materials can withstand the maximum 60-year normal radiation dose for their installed locations with only minor to moderate damage possible. Aging effects caused by radiation exposure would not adversely affect the function of any insulated cables and connections during the current or extended period of operation. Therefore, aging effects related to radiation and oxygen are not applicable for the cables included in this evaluation.

D.4.6.3 Low-voltage and medium-voltage cable insulation—heat, oxygen

The total thermal life of insulated cable and connection materials can be calculated using the Arrhenius method as described in EPRI NP-1558 [B12]. The Arrhenius method is normally used to calculate a thermal life at a given temperature; however, it can be used to calculate a maximum continuous temperature for a specific length of time. Therefore, by using the Arrhenius method in this way, with the time period fixed at 60 years, calculations were performed to determine the maximum continuous temperature to which the material can be exposed so that the material has the indicated end-of-life condition at the end of 60 years.

The typical end-of-life condition for cable thermal aging data is 40–60% retention of elongation. NUREG/CR-6384 [B73] determined that the retention of elongation of most cable insulation materials can be reduced to 0% and the insulation is still capable of withstanding a loss-of-coolant accident (LOCA) and remain functional. The point in citing this reference is to establish that it is recognized that cables can remain functional even if elongation drops well below the normally cited 40–60% retention of elongation.

As discussed previously, EQ cables are not included in this evaluation. Therefore, the cables being evaluated are either not subjected to an accident environment or are not required to function during or after being subjected to an accident environment. As a result, the end-of-life conditions chosen for this review are conservative and the 60-year life temperatures summarized in Table D.20 are also conservative.

Comparison of the maximum 60-year life temperatures given in Table D.20, with the service conditions shown in Table D.14, indicates that, except for EP, EPR, EPDM, and FR-EPR used in power applications, the insulation materials can withstand the bounding temperatures for at least 60 years.

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Table D.19—Cable material radiation dose data

Material	Lowest threshold dose in rad (in Grays)	Moderate damage dose in rad (in Grays)	References and additional comments[a]
Kapton	1×10^7 (1×10^5)	2×10^8 (2×10^6)	
XLP, XLPE, FR-XLPE	1×10^6 (1×10^4)	1×10^8 (1×10^6)	
EP, EPR, EPDM, FR-EPR	1×10^6 (1×10^4)	5×10^7 (5×10^5)	
PE	3.8×10^5 (3.8×10^3)	2×10^7 (2×10^5)	
PVC	1×10^5 (1×10^3)	2×10^7 (2×10^5)	
Butyl	7×10^5 (7×10^3)	5×10^6 (5×10^4)	
SR	1×10^6 (1×10^4)	3×10^6 (3×10^4)	
Hypalon	5×10^5 (5×10^3)	2×10^6 (2×10^4)	
Polyalkene	No data	No data	No data could be obtained for polyalkene. However, the material was tested and the material is described as "irradiation cross-linked polyalkene" which means that the material is subjected to radiation as part of the manufacturing process (similar to irradiation cross-linked polyethylene, commonly known as XLPE). Since the irradiation process is used to strengthen the material, it is assumed that it has a relatively high resistance to radiation after the manufacturing process.
Fiberglass	None	None	Fiberglass is spun glass and is not affected by radiation (except for some change in color).

[a]Unless otherwise indicated, dose data is from Table 4-7 of EPRI NP-1558 [B12] or Appendix C of SAND96-0344 [B74].

EP, EPR, EPDM, and FR-EPR assessment

The bounding service temperature for EP, EPR, EPDM, and FR-EPR is 70.6°C (159°F). The maximum temperature for a 60-year life is 68.3 °C (155 °F), which is 2.3 °C (4 °F) less than the bounding service temperature. This difference is very small and is considered to be within the conservatisms incorporated into the bounding service temperature for the following reasons:

a) The condition at the end of 60 years for EP, EPR, EPDM and FR-EPR is 40% retention of elongation. Since the cables and connections subject to an aging management review either are not subjected to accident conditions or are not required to remain functional during or after an accident, these values can be reduced much further without a loss of function. With a difference of 2.3°C (4 °F), the actual condition at the end of 60 years may be slightly lower than 40% but still much more than required for the cable to perform its function.

b) The bounding temperature includes a calculated self-heating temperature rise that assumes normal operation 100% of the time since initial operation. The units have historically operated less than 75% of the time since initial operation. This amount of shutdown time lessens the amount of aging actually occurring and thus extends the life of the material.

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Given these conservatisms, there is reasonable assurance that EP, EPR, EPDM, and FR-EPR insulated cables do not thermally age through the extended period of operation to the point that they are not able to perform their function.

Therefore, aging effects related to heat and oxygen are not applicable for the cables included in this evaluation.

Table D.20—Cable material temperature data

Insulation	Maximum temperature for a 60-year life	Condition at the end of 60 years
SR	133.9 °C (273 °F)	50% retention of elongation
Kapton	20.0 °C (248 °F)	Failure
Polyalkene	87.2 °C (189 °F)	Mean time to failure
XLP, XLPE, FR-XLPE	86.7°C (188°F)	60% retention of elongation
EP, EPR, EPDM, FR-EPR	68.3°C (155°F)	40% retention of elongation
Hypalon	67.8°C (154°F)	50% elongation
PE	55.0°C (131°F)	T_{75} induction period
Butyl	51.7°C (125°F)	40% retention of elongation
PVC	44.4 °C (112 °F)	Mean time to failure
Fiberglass	Does not age from heat	—

D.4.7 Aging management

No applicable aging effects were identified for the cables included in this evaluation. Therefore, no aging management is required.

D.5 Electrical penetration assemblies (EPAs)

EPAs are pipe-enclosed cable assemblies that provide electrical continuity through a pressure-retaining boundary while maintaining the pressure boundary. The assembly consists of a pipe segment, head plates, penetration cables, pigtails to field cabling connection points, and a penetration cabling sealing system.

D.5.1 Define evaluation boundaries

The EPA includes the pipe segment, head plates and associated penetration cabling sealing system, penetration cabling, and pigtails to the field connection points. The field wiring is not included. If the field wiring is connected to the penetration cabling via terminal blocks, then the terminal blocks are included in the evaluation. If the field wiring is connected to the penetration cabling via connectors, then the connectors are not included in the evaluation.

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D.5.2 Identify safety functions

The EPA has four functions:

a) *Pressure boundary* (*PB*)—to maintain the structural function of environmental isolation during design basis events.

b) *Electrical continuity* (*EI*)—to maintain circuit integrity under anticipated service and design conditions.

c) *Dielectric strength* (*DS*)—to prevent dielectric breakdown during anticipated service or design conditions (power and control circuits).

d) *Insulation resistance* (*IR*)—to limit leakage current to a level that does not challenge the required accuracy of the instrument signal.

D.5.3 Identify plant locations

The EPAs penetrate the containment wall at the electrical penetration rooms in the auxiliary building.

D.5.4 Identify service conditions

D.5.4.1 Ambient thermal conditions

	Electrical penetration rooms		**Containment**	
	Min	**Max**	**Min**	**Max**
Normal ambient	23.9 °C (75 °F)	32.2 °C (90 °F)	37.8 °C (100 °F)	48.9 °C (120 °F)
Design maximum	N/A	40.0 °C (104 °F)	N/A	148.9 °C (300 °F)

Knowledge of the thermal stress history allows more precision in the aging assessment. An equivalent annual exposure temperature can be calculated using Arrhenius modeling. This temperature is between the minimum and maximum service temperature. Regularly scheduled shutdown periods should be included in the thermal history.

D.5.4.2 Radiation stress

	Electrical penetration rooms	**Containment**
Normal service dose	Not significant	1.5 Mrad (15 kGy)
Dose rate	Not significant	1 rad/h (0.01 Gy/h)
DBE dose	Not significant	20 Mrad (200 kGy)

Note that equipment performance during DBEs is outside the scope of this aging assessment.

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D.5.4.3 Other stressors

Exposure to chemical spray and saturated steam during design basis events occur on the containment side of the EPA.

Note that equipment performance during DBEs is outside the scope of this aging assessment.

D.5.4.4 Self-heating

Consider ohmic heating of the penetration cabling. Also consider radiative and convective heating from adjacent energized penetration cabling in the same EPA.

D.5.5 Identify materials of construction

Subcomponents	Material
Sealing materials	Silicone rubber
Pigtail wiring insulation	Ethylene propylene rubber
Penetration cabling insulation	Kapton
Head plate	304 stainless steel
Pipe segment	Carbon steel

Associate service conditions with subcomponents. Use peaks for a conservative analysis. Normalizing a stressor such as temperature is possible if the stressor history is known or can be determined. Variations in specific formulations and manufacturing processes within a generic category of materials can result in a wide range of aging characteristics. Therefore, identification of materials of construction at a generic level limits the degree of precision that can be obtained in a quantitative life model.

D.5.6 Identify and assess aging effects

a) Thermal aging of cabling insulation material resulting in challenges to the IR, DS functions.

b) Radiation aging of exposed insulation material resulting in challenges to the IR, DS functions.

c) Thermal aging of sealing material resulting in a challenge to the PB function.

d) General corrosion of pipe segment resulting in a challenge to the PB function.

Determine the rate of degradation of susceptible materials either qualitatively or quantitatively. Identify the subcomponent that ages at the fastest rate. This is the limiting material for an aging assessment. Consider synergisms. An estimated life under anticipated service conditions can be developed by modeling if a suitable model is available. However, recognize the limitations, sensitivities, and constraints of such models. Arrhenius modeling has many limitations, sensitivities, and constraints (see 6.6.3).

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D.5.7 Aging management

D.5.7.1 Aging effects

a) Thermal aging of cabling insulation material

b) Radiation aging of exposed insulation material

c) Thermal aging of sealing material

d) General corrosion of pipe segment

D.5.7.2 Determination of life by test

The thermal and radiation aging of insulation and sealing materials can be addressed by IEEE Std 323 qualification testing. Such testing exposes the EPA to levels of radiation and heat stress that simulates the stress seen by the EPA over its design life. The EPA is functionally tested following this exposure. Any anomalies are evaluated for impact. The life-limiting material drives the IEEE Std 323 qualification testing. Lifetime qualifications of other EPAs may be useful. However, significant differences should be evaluated. Differences in design conditions, installation details, and service conditions should be assessed to determine the applicability of other EPA qualification results.

D.5.7.3 Determination of life by model

Thermal aging can be modeled by using Arrhenius methodology if the specific material life characteristic is known. A conservative life characteristic, one that envelops the life characteristic of the specific material, can be used. The use of Arrhenius assumes that a single aging mechanism is at work. The life model parameters; e.g., activation energy, may also be sensitive to the range of the stressor seen by the subcomponent.

Radiation aging may be determined to be insignificant if the exposure of sensitive materials over the life of the EPA is below the damage threshold for each material.

D.5.7.4 Condition monitoring

Correlation of monitored parameters to the functionally critical material characteristics ensures that the condition monitoring program protects the safety functions. The critical characteristics should be well behaved; the plot of the characteristic over time should not include points of inflection or cycle between minimum and maximum values. The critical characteristic should reflect a discernible trend over time.

D.5.7.5 Mitigation of aging

Mitigation of radiation aging requires shielding or the substitution of less sensitive materials. Cooling the EPA can mitigate thermal aging.

Applying anticorrosion coating to the pipe segment can mitigate corrosion of the pipe segment.

D.5.7.6 Discovery of aging effects

Degradation of the pressure boundary function can be discovered by local leak rate testing if the EPA design accommodates such testing. Electrical testing can discover degradation of the IR or DS functions. However, there is evidence that dielectric breakdown tests can degrade insulation. Therefore, the routine use of such tests is not recommended.

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Annex E

(informative)

Aging management program attributes

NOTE—The information in this annex is provided for the sole purpose of illustrating the aging assessment methodology in the body of the guide and does not represent an IEEE or industry position on any of the equipment or systems that are addressed.

The program attributes in Table E.1, as applicable, should be considered when fully defining the needed aging management actions.

Table E.1—Aging management program description

Program elements	Program element description
Purpose	A clear statement of the objective of the aging management actions.
Scope	A description of the equipment or equipment parts included.
Aging effects	A description of the applicable aging effects to be managed.
Program details	A description of actions to be taken, methods to be followed or technique to be used to manage the applicable aging effects (e.g., visual inspection, Doble testing, replacement).
Sample size	If a one-time or periodic inspection is to be performed, determine the number of equipment or equipment parts to be inspected in relation to the total population.
Frequency	The established frequency of the aging management actions that are adequate for equipment replacement or to detect the applicable aging effects prior to a loss of equipment safety function. Related to material property and stressor intensity.
Acceptance criteria	Measurable threshold values or identifiable criteria that can be used to a) Determine acceptability of the current physical configuration, and b) Trigger appropriate actions prior to a loss of equipment safety function.
Corrective action	Actions to be taken when an acceptance criteria is not met.
Program initiation	A description of the first time when the actions of the program are to take place.
Industry codes or standard	Identification of industry codes or standards (NRC-approved if appropriate) in accordance with which the aging management actions are to be performed.
Administrative controls	Identification or description of the plant procedure or other administratively controlled process under which the program is to be implemented.
Regulatory basis	Any existing regulatory basis for the aging management actions (e.g., UFSAR or technical specifications requirements).

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After the applicable aging management program elements have been identified, these should be compared to existing performance, condition monitoring, or maintenance activities already being performed for the equipment. If the needed aging management actions are enveloped by existing activities, no new programs or enhancements are needed. If the needed aging management actions are not included in existing activities, new programs or enhancements to existing programs or procedures should be initiated to address the equipment aging management concerns.

a) Define the specific aging management program elements needed to fully manage the applicable electrical equipment aging effects.

b) Compare the needed aging management program actions to existing performance, condition monitoring, or maintenance activities being performed for the equipment.

c) If the needed aging management actions are enveloped by existing activities, no new programs or procedure enhancements are needed.

d) If the needed aging management actions are not included in existing activities, initiate new programs or enhancements to existing programs or procedures to address the equipment aging management concerns.

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Annex F

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